Maintaining Reliable Supply to the North West Slopes Area

RIT-T - Project Assessment Conclusions Report

Region: Northern New South Wales

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Executive summary

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options for maintaining reliable supply to the North West Slopes area of northern New South Wales (NSW). Publication of this Project Assessment Conclusions Report (PACR) represents the final stage in the RIT-T process and follows the Project Assessment Draft Report (PADR) released on 18 February 2022.

Overview

The preferred option identified in this PACR involves a non-network solution provided through a BESS at the Gunnedah 132 kV substation and the installation of a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation in the near-term. It also involves the rebuilding of the existing 969 line between the Tamworth 330 kV and Gunnedah substations as a double circuit line and upgrading the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA over the longer-term, depending on outturn demand forecasts.

The proposals of two separate third party non-network BESS proponents have been found to be ranked effectively equal in the PACR assessment. These options are referred to as Option 5B and Option 5C in the PACR, and reflect the proposed BESS component followed by the network investment outlined above. These options are found to deliver approximately $513 million and $496 million in net benefits, respectively, relative to the 'do nothing' base case on a weighted basis, which compares to $470 million for the preferred solely network option (Option 3A).[1] The proposal of the third BESS proponent (assessed as Option 5A) has been found to deliver lower net benefits than these two options but to effectively be ranked equally with Option 3A.

The non-network solutions will provide up to 57 MW and 20 MVAr in the Gunnedah area, providing both network and dynamic reactive support by 2030 to manage thermal constraints and voltage variations during high demand periods. Options with non-network solutions generally have higher net benefits because they can be deployed an estimated one to two years earlier than the pure network options, avoiding significant unserved energy in that period.

We will now enter into a competitive procurement process and commercial negotiations with non-network proponents for a network support contract and seek to put in place a contract with one of these parties. We consider these negotiations should involve all proponents involved in the RIT-T process (i.e., including Option 5A, which has lower estimated net benefits than the other two non-network options) and potentially others who are able to provide the same kind of solution within the required timeframe, since the timing of when BESS can be implemented is critical to which solution is ultimately preferred (and may be able to be refined through the negotiation process). In addition, we consider that having more parties involved in this process will ensure that the network support costs paid for by consumers are as efficient as possible.

Notwithstanding the above, we consider that if either of the following two events occur, they would likely constitute a 'material change in circumstances' (i.e., under clause 5.16.4(z3) of the NER):

1. None of the non-network proponents being able to commit to having the BESS in place to provide network support by a date that ensures that option continues to be considered as the top-ranked option under the RIT-T; or

2. Transgrid not being able to finalise a network support contract with any of the proponents that is expected to be accepted as prudent and efficient by the AER.

[1] Option 3A includes an additional network component to Options 5A-5C, as well as earlier investment in some components.

Should either (or both) of these events occur, we would seek an exemption from the AER under clause 5.16.4(z3) of the NER to avoid having to reapply the RIT-T. Specifically, we consider that, should either of the above events occur, then the analysis presented in this PACR demonstrates that Option 3A (i.e., the top ranking solely network option) should then be considered the preferred option under this RIT-T.

We consider this approach provides sufficient confidence that Transgrid will be able to progress an option to ensure the externally-imposed regulatory obligations and service standards this RIT-T is designed to meet are met at an efficient cost level without having to re-do the RIT-T. We note that re-doing the RIT-T would take significant time, which would compromise the reliability of supply to customers in the North West Slopes area and ultimately likely cost all NSW electricity customers more in the long-run.

We will update stakeholders when we consider that the network support agreement for one of these options is sufficiently certain, or at the point we determine there has been a material change in circumstances and that the investment should be progressed as a solely network option (i.e., Option 3A) (i.e., when we would submit an exemption to the AER from having to reapply the RIT-T).

All non-network options, as well as Option 3A, are expected to generate sufficient benefits to recover their costs within two years of commissioning their respective long-term solutions (under the weighted results and in present value terms).

The identified need driving investment

Our latest forecasts indicate that electricity demand is expected to increase substantially in the North West Slopes area going forward due to a number of substantial industrial loads that are anticipated to connect, as well as underlying general load growth in Narrabri and Gunnedah.

Schedule 5.1.4 of the National Electricity Rules (NER) requires us to plan and design equipment for voltage control to maintain voltage levels within 10 per cent of normal voltage.[2] The NER also requires the power system to be operated in a satisfactory operating state, which requires voltages to be maintained within these levels, both in normal operation and following any credible contingency event.[3]

We have undertaken planning studies that show that the current North West Slopes network will not be capable of supplying the combined increases in load in the area without breaching the National Electricity Rules (NER) requirements and that voltage-limited constraints will have to be applied in the 132 kV supply network if action is not taken, leading to substantial levels of unserved energy to end customers. Our planning studies also show that the increased demand will also lead to thermal constraints going forward, particularly during times of low renewable generation dispatch in the region.

If the longer-term constraints associated with the load growth are unresolved, it could result in the interruption of a significant amount of electricity supply under both normal and contingency conditions due to voltage and thermal limitations in the area.

[2] These levels are specified in Clause S5.1a.4.

[3] These requirements are set out in Clauses 4.2.6, 4.2.4 and 4.2.2(b) of the NER. The requirement for secure operation of the power system in Clause 4.2.4 requires the power system to be in a satisfactory operating state following any credible contingency event, that is, to maintain voltage within 10 per cent of normal voltage following the first credible contingency event.

This RIT-T has therefore examined various network and non-network options for relieving these constraints going forward to ensure compliance with the requirements of the NER and provide the greatest net benefit to the market. We consider this a 'reliability corrective action' under the RIT-T as the proposed investment is for the purpose of meeting externally-imposed regulatory obligations and service standards, i.e., Schedule 5.1.4 of the NER.

Benefits from the options considered in this PACR

Without action, voltage-limited constraints will have to be applied in the 132 kV supply network that will lead to substantial levels of unserved energy to end customers. We are taking action under this RIT-T in order to avoid this outcome. All of the credible options have been designed to maximise the avoided unserved energy expected and ensure compliance with the requirements of the NER.

In addition, some of the credible options assessed also affect the wholesale electricity market. In particular, four of the options involve grid-connected BESS that are expected to introduce new entities trading in the wholesale market, eg, dispatching into the National Electricity Market (NEM) outside of the allocation of storage needed to meet network support commitments.

Both the benefits from the provision of reliable supply to the North West Slopes area and wider wholesale market benefits have been estimated as part of this PACR.

Key developments since the PADR have been reflected in the PACR

There have been a number of key developments since the PADR was released in February 2022, which impact the analysis in this RIT-T. In particular:

- the demand forecasts have been updated based on additional information provided by proponents of new or expanded industrial spot loads, as well as updated information on general load growth from Essential Energy;
- our forecasts of when voltage and thermal limits are expected to be breached have been updated in light of the revised demand forecasts;
- the wholesale market modelling has been updated to reflect the assumptions underpinning AEMO's draft 2022 Integrated System Plan (ISP) and is now focused on the step-change, progressive change and hydrogen superpower scenarios (the scenario weightings have also been updated to be consistent with the draft 2022 ISP);
- there have been a number of updates to the non-network options that were assessed in the PADR (Option 5A and Option 5B), including to reflect new information provided by the proponents;
- a new non-network option (Option 5C) has been included in the assessment following a submission to the PADR;
- there has been an update to the assumptions regarding how BESS components are likely to be able to trade in the wholesale market, based on further analysis of the amount of storage that would be required to be reserved to provide network support; and
- there have been a number of updates to the network options, including revised costs and reactive support sizing.

The key changes in the PACR demand forecasts compared to the PADR are:

- Essential Energy providing revised general demand forecasts for the region as part of an annual update;
- the inclusion of the Narrabri Coal expansion in the central demand forecast (this is a new spot load that was not included in Essential Energy's demand forecasts at the time of the PADR); and
- a one year delay to the commencement of the expansion of the existing Vickery Coal Mine (VCM).

The last two changes above reflect additional information provided by proponents following the PADR.

There has been no change to the Narrabri Gas Project load reflected in the demand forecasts since the PADR.

We received submissions from four parties in response to the PADR. While submissions covered a range of topics, there were five main topics that emerged:

- a new non-network option was proposed by one submitter (and has been included in the PACR assessment as a new Option 5C);
- further details regarding earlier proposed non-network options were provided by the proponents;
- uncertainty around the demand forecasts;
- a proposal for an alternate conductor technology, that could reduce the network option costs; and
- the appropriateness of the 'high benefits' scenario.

The key matters raised in public submissions relevant to the RIT-T assessment are summarised in this PACR, together with our responses and how the matters raised have been reflected in the assessment. Many of the submissions were confidential and we have engaged directly with those parties on the points raised.

The PACR assessment covers four different types of credible options

This PACR assesses both network options and options involving non-network components followed by network investment.[4]

Each of the credible network options requires the installation of a third 60 MVA 132/66 kV transformer at Narrabri due to the firm supply capacity of the existing transformers at this location being exceeded and to ensure the reliability standard set by the Independent Pricing and Regulatory Tribunal (IPART) is met for Narrabri in the short-term.

Aside from the new 132/66 kV transformer at Narrabri, the credible network options assessed differ in the near-term by where, how and when new capacity is added to the North West Slopes region. In particular, there are three broad types of credible network option assessed that centre on:

- uprating the existing line 969 from Tamworth to Gunnedah (Option 1A and Option 1B);
- installing new single or double circuit transmission lines between Tamworth and Gunnedah (Option 2A, Option 2B, Option 2C and Option 2D); and

[4] Non-network options by themselves are not expected to be able to meet the identified need over the entire assessment period.

- rebuilding the existing line 969 from Tamworth to Gunnedah to be a double circuit line (Option 3A, Option 3B and Option 3C).

Most credible options include the provision of dynamic reactive support at Narrabri provided by an SVC or grid-scale BESS. Two options (Option 2C and Option 3C) involve a new transmission line between Gunnedah and Narrabri as an alternative to dynamic reactive support and the upgrade to the 9UH line.

While there have been no material changes to the network options since the PADR, the non-network options considered in the PACR assessment have been refined to reflect:

- submissions to the PADR, resulting in the timing of Option 5A being brought forward by six months from the PADR, minor revisions to the estimated costs of Option 5A and Option 5B and the inclusion of a third non-network option (Option 5C); and
- elements of the non-network options being resized and rescoped following additional information provided by proponents.

The non-network solutions have been modelled in terms of their ability to efficiently defer or avoid the rebuilding of line 969 as a double-circuit line,[5] which is part of the preferred solely network option (Option 3A).

Non-network options are not able to avoid or defer the need for the initial third transformer required at Narrabri, since capacity is required there immediately to ensure the reliability standard set by IPART is met at Narrabri. The non-network options therefore reflect a combination of an initial non-network component and a third Narrabri transformer in all scenarios, followed by a deferred rebuilding of line 969 as a double-circuit line and upgrading the 9UH line between Narrabri and Boggabri North in the central and high scenarios when the Narrabri Gas Project comes online.

Table E-1 below summarises each of the credible options assessed in the PACR.

Table E-1: Summary of the credible options

Option	Description	Estimated capex ($2020/21)
	Uprating the existing line 969 from Tamworth to Gunnedah	
1A	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA	• $51 million
	• Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah substation	• $18 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
	• Upgrade the existing 968 line between Tamworth 330 and Narrabri substations to a rating of at least 160 MVA	• $149 million
	• Install a 132 kV +60 MVAr -20 MVAr SVC at Narrabri	• $20 million

[5] The rebuilding of this line is required when the Narrabri Gas Project comes online.

Option	Description	Estimated capex ($2020/21)
1B	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA	• $51 million
	• Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah substation	• $18 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
	• Build a new 132 kV line between Tamworth 330/132 kV and Narrabri 132/66 kV substations	• $160 million
	New single or double circuit transmission lines between Tamworth and Gunnedah	
2A	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new single circuit 160 MVA 132 kV line between Tamworth 330 kV and Gunnedah substations.	• $73 million
	• Upgrade the existing 969 line to a rating of 135 MVA	• $51 million
	• Upgrade the 9UH line to a rating of 100 MVA	• $28 million
	• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	• $20 million
2B	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new double circuit 132 kV line between the Tamworth 330 kV and Gunnedah substations, each circuit rated at 160 MVA. Decommission the existing 969 transmission line	• $89 million
	• Upgrade the 9UH line to a rating of 100 MVA	• $28 million
	• Installation of a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	• $20 million
2C	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new single circuit 160 MVA 132 kV line between Tamworth 330 kV and Gunnedah substations	• $73 million
	• Upgrade the existing 969 line to a rating of 135 MVA	• $51 million
	• Build a new single circuit 132 kV line between Narrabri and Gunnedah	• $106 million
2D	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new single circuit 330 kV line between Tamworth 330 kV and Gunnedah substations operated at 132 kV, rated at least 160 MVA	• $159 million
	• Upgrade the existing 969 line to a rating of 135 MVA	• $51 million
	• Upgrade the 9UH line to a rating of 100 MVA	• $28 million
	• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	• $20 million
	Rebuilding the existing line 969 from Tamworth to Gunnedah to be a double circuit line	

Option	Description	Estimated capex ($2020/21)
3A	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
	• Install a 132 kV +60 MVAr (capacitive) -20 MVAr (inductive) SVC at Narrabri substation	• $20 million
3B	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
	• Install a 50 MW (50 MWh) BESS at Narrabri 132 kV	• Confidential
3C	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Build a new single circuit 132 kV line between Narrabri and Gunnedah	• $106 million
Combination of non-network solutions with the top-ranked network option (Option 3A)		
5A	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Install a BESS at Gunnedah 132 kV as a network support service	• Confidential
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
5B	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Install a BESS near Gunnedah 132 kV as a network support service	• Confidential
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
5C	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Install a BESS at Gunnedah 132 kV as a network support service	• Confidential
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million

Option	Description	Estimated capex ($2020/21)
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million

Capital costs for the network options have been revised since the PADR to reflect the change in size of some elements, as well as to reflect current market trends and risks, drawing on the experience of recent projects. In addition, works for the line 969 double-circuit rebuild, and the 9UH line uprating, now reflect the use (and costs) of an alternate conductor technology proposed in response to the PADR.

Three scenarios have been assessed

The RIT-T is focused on identifying the top ranked credible option in terms of expected net benefits. However, uncertainty exists in terms of estimating future inputs and variables (termed future 'states of the world').

To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to determine a weighted ('expected') net benefit. It is this 'expected' net benefit that is used to rank credible options and identify the preferred option.

The credible options have been assessed under three scenarios as part of this PACR assessment, which differ in terms of the key drivers of the estimated net market benefits.

The three scenarios are characterised as follows:

- a 'low net economic benefits' scenario, involving a number of assumptions that gives a lower bound , conservative estimate of the present value of net economic benefits;
- a 'central' scenario based on a central set of variable estimates and reflects the most likely scenario; and
- a 'high net economic benefits' scenario that reflects a set of assumptions selected to investigate an upper bound of net economic benefits

The table below summarises the specific key variables that influence the net benefits of the options under each of the scenarios considered.

Table E-2: Summary of scenarios

Variable	Central	Low net economic benefits	High net economic benefits
Network capital costs	Base estimate	Base estimate + 25%	Base estimate - 25%
Non-network capital costs	Base estimate	Base estimate + 25%	Base estimate - 25%
Demand	Central demand forecast	Low demand forecast	Central demand forecast
New renewable generation in the area	In-service and committed generators from Appendix B.	All in-service, committed and advanced generators from Appendix B.	In-service and committed generators from Appendix B.
Wholesale market benefits estimated	EY estimated based on the step-change 2022 ISP scenario	EY estimated based on the progressive change 2022 ISP scenario	EY estimated based on the hydrogen superpower 2022 ISP scenario
VCR[6]	$46.88/kWh	$32.82/kWh	$60.95/kWh
Discount rate	5.50%	7.50%	1.96%

The wholesale market modelling has been updated since the PADR and we now model the market benefits of the options (where relevant) across the three key 2022 ISP scenarios. We have also weighted each of the scenarios for this RIT-T based on the draft 2022 ISP weightings for the underlying ISP scenarios, i.e.:

- 52 per cent to central scenario (based on the step-change scenario in the ISP);
- 30 per cent to the low benefits scenario (based on the progressive change scenario in the ISP); and
- 18 per cent to the high benefits scenario (based on the hydrogen superpower scenario in the ISP).

We have also investigated the sensitivity of the results to alternate weightings as part of this PACR (and they are found not to be sensitive).

The preferred option involves the use of BESS in the short-term coupled with network investment as demand grows

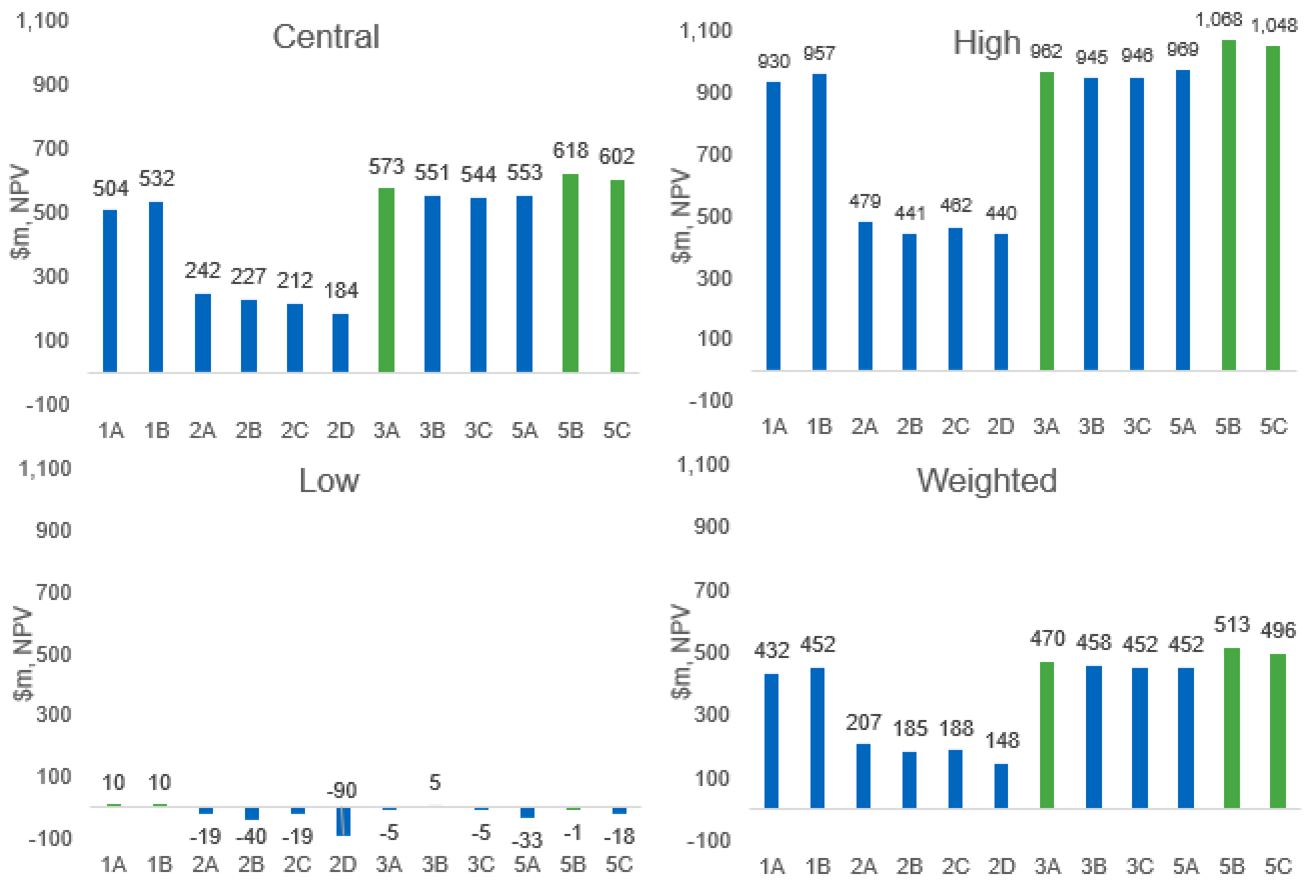
The preferred option identified in this PACR involves the use of a non-network solution provided via a new BESS at the Gunnedah 132 kV substation and the installation of a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation in the near-term. It also involves rebuilding of the existing 969 line between the Tamworth 330 kV and Gunnedah substations as a double circuit and upgrading the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA over the longer-term, depending on outturn demand forecasts.

The proposals of two separate third party BESS proponents (coupled with network investment) have been found to be ranked effectively equal in the PACR assessment. These options are referred to as Option 5B and Option 5C in the PACR and are found to deliver approximately $513 million and $496 million in net

6 The VCRs have been updated since the PADR to reflect the updated underlying demand forecasts, i.e., the load that would be affected under the base case. However, we note that this update has had only a minor impact on the estimated VCRs.

benefits, respectively, relative to the ‘do nothing’ base case on a weighted basis, which compares to $470 million for the top-ranked solely network option (Option 3A).

Figure E-1: Estimated net benefits for each scenario



The proposal of the third BESS proponent (Option 5A) has been found to deliver lower net benefits than Option 5B and Option 5C and effectively be ranked equally with Option 3A.

While Option 3A has the second lowest expected total cost of the solely network options, in present value terms, under the weighted outcome, it can avoid a substantial amount of unserved energy one to two years earlier than the lowest cost network option (Option 2B).[7] Option 3A also has the lowest cost, in real terms, of the solely network options. Option 3A is therefore considered the preferred solely network option and is therefore the network option the non-network options have been coupled with.[8]

Almost all of the estimated gross benefits across all of the options are derived from avoided unserved energy, which makes up between 89 and 92 per cent of the total gross benefits of Options 5A-5C on a weighted basis (and 100 per cent for Option 3A since that option does not affect the wholesale market). We note also that we have applied a conservative approach to valuing these benefits, whereby all unserved energy in the later years of the assessment period is not valued (since it is common to all options), in order to enable the most meaningful comparison between options.

[7] The present value of all capex and opex of Option 3A under the weighted outcome is $91 million, which compares to $83 million for Option 2B.
[8] The non-network solutions are able to defer or avoid the rebuilding of line 969 as a double-circuit line under Option 3A.

While most options are found to have net costs under the low scenario, meaning that they are not preferred over the base case 'do nothing' option, we note that these net costs are only marginal and, if we did not apply the approach to removing unserved energy in the later years of the assessment period, all options would be found to have significantly positive net benefits.

Moreover, while the low scenario yields different top-ranked options, we do not consider this material to the overall conclusion of the RIT-T (i.e., that the non-network options are preferred) given the quantity of unserved energy expected to be avoided across the scenarios. The low scenario would need to be given an unreasonably high weighting in order to change the conclusion of this PACR. Specifically, we find that the low scenario would need to be given a weighting of approximately 74 per cent in order for either Option 5B or Option 5C to be ranked below any of the purely network. [9]

Further information and next steps

This PACR represents the final formal stage in the RIT-T process.

We will now enter into a competitive procurement process and commercial negotiations with non-network proponents for a network support contract and seek to put in place a contract with one of these parties.

Notwithstanding the above, we consider that if either of the following two events occur, they would likely constitute a 'material change in circumstances' (i.e., under clause 5.16.4(z3) of the NER):

1. None of the non-network proponents being able to commit to having the BESS in place to provide network support by a date that ensures that option continues to be considered as the top-ranked option under the RIT-T; or

2. Transgrid not being able to finalise a network support contract with any of the proponents that is expected to be accepted as prudent and efficient by the AER..

Should either (or both) of these events occur, we would seek an exemption from the AER under clause 5.16.4(z3) of the NER to avoid having to reapply the RIT-T. Specifically, we consider that, should either of the above events occur, then the analysis presented in this PACR demonstrates that Option 3A (i.e., the top ranking solely network option) should then be considered the preferred option under this RIT-T.

We consider this approach provides sufficient confidence that Transgrid will be able to progress an option to ensure the externally-imposed regulatory obligations and service standards this RIT-T is designed to meet are met at an efficient cost level without having to re-do the RIT-T. We note that re-doing the RIT-T would take significant time, which would compromise the reliability of supply to customers in the North West Slopes area and ultimately likely cost all NSW electricity customers more in the long-run.

We note that the Rules regarding a 'material change in circumstances', and the ability to include a 'decision rule' in a PACR, is currently being considered by the Australian Energy Market Commission.[10] In the event that the NER change following this PACR, we would consider the events above to constitute two elements of a decision rule for ultimately determining the preferred option for this RIT-T.

[9] We note that this weighting does not change if we value all avoided unserved energy in the assessment, i.e., if we do not apply the approach of removing unserved energy in the later years of the assessment outlined in section 6.1 of this PACR.

[10] AEMC, *Transmission Planning and Investment Review*, Consultation Paper, 19 August 2021, p. 54.

We will update stakeholders when we consider that the network support agreement for one of these options is sufficiently certain, or at the point we determine there has been a material change in circumstances and that the investment should be progressed as a solely network option (i.e., Option 3A) (i.e., when we would submit an exemption to the AER from having to reapply the RIT-T).

As stated in our revenue proposal for the 2023-2028 period,[11] we will include the preferred option identified through the RIT-T in our augmentation expenditure forecast in our Revised Revenue Proposal for the forthcoming regulatory period. More information on our 2023-28 revenue proposal can be found here.

Further details in relation to this project can be obtained from regulatory.consultation@transgrid.com.au. In the subject field, please reference 'North West Slopes Area reliability project.'

[11] Transgrid, *Revenue Proposal 2023–2028*, 31 January 2022, p. 112.

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Contents

1. Introduction

We have applied the Regulatory Investment Test for Transmission (RIT-T) to options for maintaining reliable supply to the North West Slopes area of northern New South Wales (NSW). This PACR represents the final stage in the RIT-T process and follows the Project Assessment Draft Report (PADR) released on 18 February 2022.

As will be set out in our forthcoming 2022 Transmission Annual Planning Report (TAPR), the latest forecasts indicate that electricity demand is expected to increase substantially in the North West Slopes area going forward. This is mainly due to a number of substantial industrial loads that are anticipated to connect, as well as underlying general load growth in Narrabri and Gunnedah.

Our power system studies forecast that the expected load growth will reach voltage stability and thermal limits in the next few years on the 132 kV supply network in the North West Slopes area if action is not taken.

Schedule 5.1.4 of the National Electricity Rules (NER) requires us to plan and design equipment for voltage control to maintain voltage levels within 10 per cent of normal voltage.[12] The NER also requires the power system to be operated in a satisfactory operating state, which requires voltages to be maintained within these levels, both in normal operation and following any credible contingency event.[13]

We have undertaken planning studies that show that the current North West Slopes network will not be capable of supplying the combined increases in load in the area without breaching the NER requirements and that voltage-limited constraints will have to be applied in the 132 kV supply network if action is not taken, leading to substantial levels of unserved energy to end customers. Specifically, we forecast significant under-voltage in this region of our network if action is not taken.

Moreover, in addition to the voltage constraints identified, our planning studies show that the increased demand will also lead to thermal constraints going forward, particularly during times of low renewable generation dispatch in the region.

This RIT-T has therefore examined various network and non-network options for relieving these constraints going forward to ensure compliance with the requirements of the NER and provide the greatest net benefit to the market.

1.1. Purpose

The purpose of this PACR is to:

- identify and confirm the market benefits expected from the various options for relieving the identified constraints going forward to ensure compliance with the requirements of the NER and provide the greatest net benefit to the market over the long-term;
- summarise the submissions received on the PADR and developments since the PADR was released and highlight how these have been taken into account in the RIT-T analysis;

12 These levels are specified in Clause S5.1a.4.

13 These requirements are set out in Clauses 4.2.6, 4.2.4 and 4.2.2(b) of the NER. The requirement for secure operation of the power system in Clause 4.2.4 requires the power system to be in a satisfactory operating state following any credible contingency event, that is, to maintain voltage within 10 per cent of normal voltage following the first credible contingency event.

- describe the options assessed under this RIT-T, including how these have been shaped as part of the consultation process;
- present the results of the updated NPV analysis for each of the credible options assessed;
- describe the key drivers of these results, and the assessment that has been undertaken to ensure the robustness of the conclusion; and
- identify the overall preferred option under the RIT-T, i.e., the option that is expected to maximise net market benefits.

Overall, a key purpose of this PACR is to provide interested stakeholders the opportunity to review the analysis and assumptions and have certainty and confidence that the preferred option has been robustly identified as optimal.

We are also releasing a supplementary market modelling report on our website to complement this PACR. Detailed cost benefit results are included as a spreadsheet appendix accompanying this report.

The credible options outlined in this PACR have been developed as part of our long-term planning for the area and each involves a series of investments over the next twenty years. This RIT-T assesses all stages of these options in order to identify the most efficient series of investments to meet network needs over the long-term.

1.2. Further information and next steps

This PACR represents the final stage in the RIT-T process.

The preferred option identified in this PACR involves the use of Battery Energy Storage Systems (BESS) at the Gunnedah 132 kV substation as a non-network solution and the installation of a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation in the near-term. It also involves rebuilding of the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit and upgrading the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA over the longer-term, depending on outturn demand forecasts.

The proposals of two separate third party BESS proponents have been found to be ranked effectively equal in the PACR assessment and ahead of the preferred network option (Option 3A). The proposal of the third BESS proponent has been found to deliver lower net benefits than these two options and effectively be ranked equally with Option 3A.

We will now enter into a competitive procurement process and commercial negotiations with non-network proponents for a network support contract and seek to put in place a contract with one of these parties. The specific details of these BESS proposals have not been presented in this PACR to preserve the confidentiality requested by the proponents.

Progression of a non-network option will require the successful conclusion of a binding network support agreement between Transgrid and a BESS proponent that is acceptable to the AER. If this does not occur then we consider that the next highest ranked option, Option 3A, is to be considered the preferred option under this RIT-T.

We will update stakeholders when we consider that the network support agreement for one of these options is sufficiently certain, or at the point we determine there has been a material change in circumstances and that Option 3A should instead be progressed (i.e., when we would submit an exemption to the AER from having to reapply the RIT-T).

The estimated capital cost associated the installation of a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation ($8 million, $2020/21), which is required in 2025/26 irrespective of the demand forecast or preferred option in this PACR, will be reflected in our ex ante capital expenditure forecast as part of our forthcoming revised regulatory proposal for the 2023-28 period. In addition, part of the work involved in the subsequent network investment (i.e., rebuilding of the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit line and upgrading the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA over the longer-term) is also to be included in our ex ante capital expenditure forecast since it is expected to be required by 2029/30 under the central demand forecasts, i.e., some of the expenditure falls in the next regulatory control period.

As stated in our revenue proposal for the 2023-2028 period,[14] we will include the preferred option identified through the RIT-T in our augmentation expenditure forecast in our Revised Revenue Proposal for the forthcoming regulatory period. More information on our 2023-28 revenue proposal can be found here.

Further details in relation to this project can be obtained from regulatory.consultation@transgrid.com.au. In the subject field, please reference 'North West Slopes Area reliability project.'

[14] Transgrid, *Revenue Proposal 2023–2028*, 31 January 2022, p. 112.

2. Developments since the PADR

This section discusses the 'identified need' for this RIT-T, before outlining the key developments that have occurred since the PADR was released in February 2022. More information on the current network area is provided in Appendix B.

2.1. Summary of the 'identified need'

Schedule 5.1.4 of the NER requires us to plan and design equipment for voltage control to maintain voltage levels within 10 per cent of normal voltage.[15] The NER also requires the power system to be operated in a satisfactory operating state, which requires voltages to be maintained within these levels, both in normal operation and following any credible contingency event.[16]

We have undertaken planning studies that show that the current North West Slopes network will not be capable of supplying the forecast increases in load in the area without breaching the NER requirements and that voltage-limited constraints will have to be applied in the 132 kV supply network if action is not taken, leading to substantial levels of unserved energy to end customers. Specifically, we forecast significant under-voltage in this region of our network if action is not taken.

Moreover, in addition to the voltage constraints identified, our planning studies show that the increased demand will also lead to thermal constraints, particularly during times of low renewable generation dispatch in the region.

Demand forecasts for the area have been updated since the PADR, due to both an update from Essential Energy in terms of load in their network as well as more information being provided by key spot loads in the area regarding the status of their developments (as outlined in section 2.3).

If the longer-term constraints associated with the load growth are unresolved, it could result in the interruption of a significant amount of electricity supply under both normal and contingency conditions due to voltage and thermal limitations in the area.

This RIT-T has therefore assessed options to ensure the above NER requirements continue to be met in the North West Slopes area in light of the forecast demand increases. We consider this a 'reliability corrective action' under the RIT-T as the proposed investment is for the purpose of meeting externally-imposed regulatory obligations and service standards, i.e., Schedule 5.1.4 of the NER.

In addition, some of the credible options assessed will also affect the wholesale electricity market through the use of grid-connected storage. Both the benefits from the provision of reliable supply to North West Slopes and wider wholesale market benefits have been estimated as part of this PACR (consistent with the earlier PADR).

2.2. Wholesale market benefits expected from the use of non-network solutions

Four of the credible options assessed in this PACR involve the use of BESS, three of which have been proposed by third party proponents of these solutions. These components are expected to be able to assist

15 These levels are specified in Clause S5.1a.4.

16 These requirements are set out in Clauses 4.2.6, 4.2.4 and 4.2.2(b) of the NER. The requirement for secure operation of the power system in Clause 4.2.4 requires the power system to be in a satisfactory operating state following any credible contingency event, that is, to maintain voltage within 10 per cent of normal voltage following the first credible contingency event.

with providing reactive support in the short-term but could also use a portion of their capacity to dispatch to the wholesale market (as outlined in section 2.3.4), offsetting more costly generation that would otherwise be called to operate, and thus provide wider wholesale market benefits in addition to the avoided unserved energy that all options provide.

These wider benefits have been estimated by way of wholesale market modelling conducted by EY and are found to be made up primarily of avoided and deferred capital costs of new generation and storage.

While the other credible network options (i.e., the solely network options) will provide additional system strength to the North West Slopes region, we do not consider there to be material wholesale market benefits associated with these options. Specifically, while this additional capacity may affect the investment decisions of future local renewable generators on the 132 kV network, upstream 330 kV network constraints outside of this RIT-T (particularly south of Tamworth) mean that any new generation is not expected to displace the output of generation elsewhere and so there is not expected to be any material wider wholesale market impacts between the options and the base case. As a consequence, these credible options do not address network constraints between competing generators and so will not have an impact on generation dispatch outcomes and the wholesale electricity market.

None of the options are expected to add to, or takeaway from, any wholesale market benefits from future expansions of QNI over the longer term (e.g., 'QNI Connect' referred to in the draft 2022 ISP). These future upgrades of QNI are expected to be 330 kV and will not tie into the 132 kV network in the North West Slopes area (despite likely passing nearby).

2.3. Developments since the PADR was released in February 2022

A number of key developments have occurred since the PADR was released, which impact the analysis in this RIT-T. In particular:

- the demand forecasts have been updated based on additional information provided by proponents of new or expanded industrial spot loads, as well as updated information on general load growth from Essential Energy;
- our forecasts of when voltage and thermal limits are expected to be breached have been updated in light of the revised demand forecasts;
- the wholesale market modelling has been updated to reflect the assumptions underpinning AEMO's draft 2022 Integrated System Plan (ISP) and is now focused on the step-change, progressive change and hydrogen superpower scenarios (the scenario weightings have also been updated to be consistent with the draft 2022 ISP);
- there have been a number of updates to the non-network options that were assessed in the PADR (Option 5A and Option 5B), including to reflect new information provided by the proponents;
- a new non-network option (Option 5C) has been included in the assessment following a submission to the PADR;
- there has been an update to the assumptions regarding how BESS components are likely to be able to trade in the wholesale market, based on further analysis of the amount of storage that would be required to be reserved to provide network support; and
- there have been a number of updates to the network options, including revised costs and reactive support sizing.

Each of these developments is discussed in the sections below.

2.3.1. Demand forecasts have been updated since the PADR

Demand forecasts are a key driver of the identified need for this RIT-T and are expected to increase significantly in the North West Slopes power system due to both underlying general load growth as well as specific spot load developments coming online. The PACR has considered two demand forecasts (the central and low forecasts) representing different assumed quantities, timings and locations for key loads.

The key changes in the PACR demand forecasts compared to the PADR are:

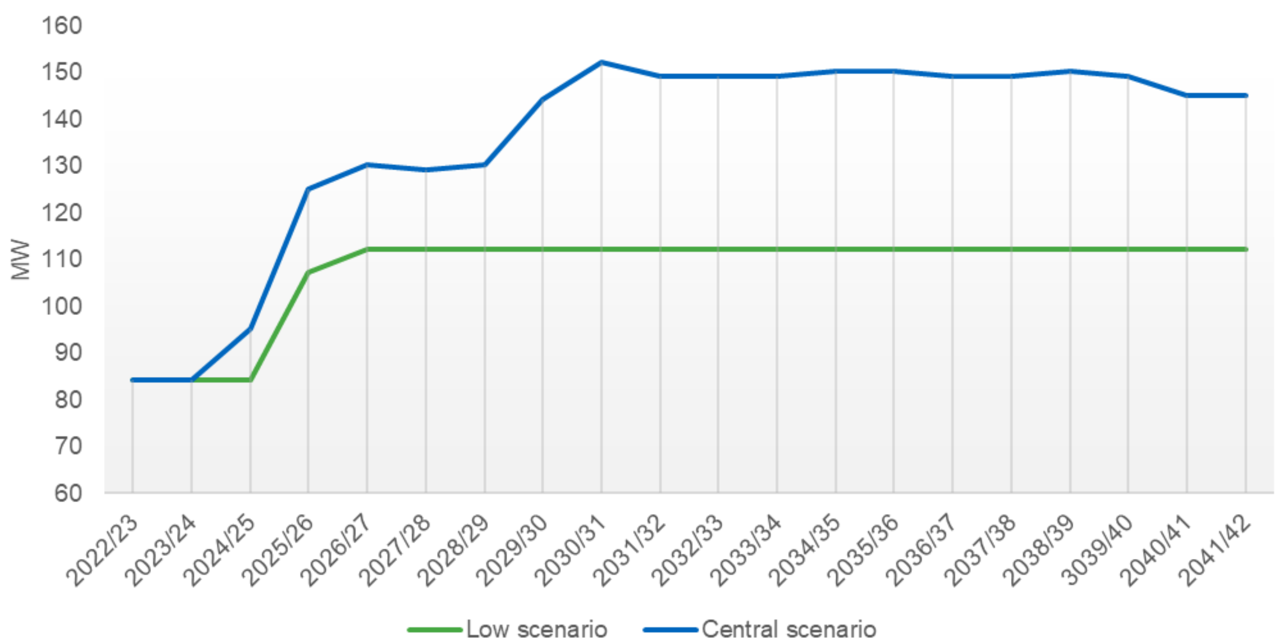
- Essential Energy providing revised general demand forecasts for the region as part of an annual update;
- the inclusion of the Narrabri Coal expansion in the central demand forecast (this is a new spot load that was not included in Essential Energy's demand forecasts at the time of the PADR); and
- a one year delay to the commencement of the expansion of the existing Vickery Coal Mine (VCM).

The last two changes above reflect additional information provided by proponents following the PADR.

There has been no change to the Narrabri Gas Project load reflected in the demand forecasts since the PADR.

Figure 2 presents the updated peak demand forecasts used in the PACR assessment.

Figure 2: Peak demand forecasts for the North West Slopes area



As in the PADR, the PACR does not include a high demand forecast since no additional loads are considered sufficiently committed to include at this stage.[17] The 'high economic benefits' scenario investigated in this PACR therefore applies the central demand forecast (as outlined in section 5.1 below).

The key spot loads are reflected in the demand forecasts used in this PACR as follows:

- Central forecast:
  - assumes that VCM, the Narrabri Coal expansion, and the Narrabri Gas Project connect; and
  - assumes the full forecast for the Narrabri Gas Project (Stages 1 and 2).
- Low demand forecast:
  - VCM and the Narrabri Coal expansion do not connect;
  - only Stage 1 of the Narrabri Gas Project is assumed to connect.[18]

The demand forecasts therefore reflect the various stages of potential development for the key loads and allow the PACR to assess how the net benefit of the options considered varies depending on differing assumptions around the progression of later development stages.

Essential Energy have also provided revised general demand forecasts for the region as part of an annual update. However, this has only had a minor impact on the load forecasts at Gunnedah and Narrabri, both of which have increased slightly (and will be reflected in our forthcoming 2022 TAPR).

2.3.2. Forecast of when voltage and thermal limits are expected to be breached if action is not taken

The changes in the load forecasts have not had an impact on when the forecast voltage and thermal limits are expected to be breached if action is not taken compared to what was presented in the PADR.

Specifically, our system studies continue to show that the available capacity in the North West Slopes area is limited following connection of key loads by:

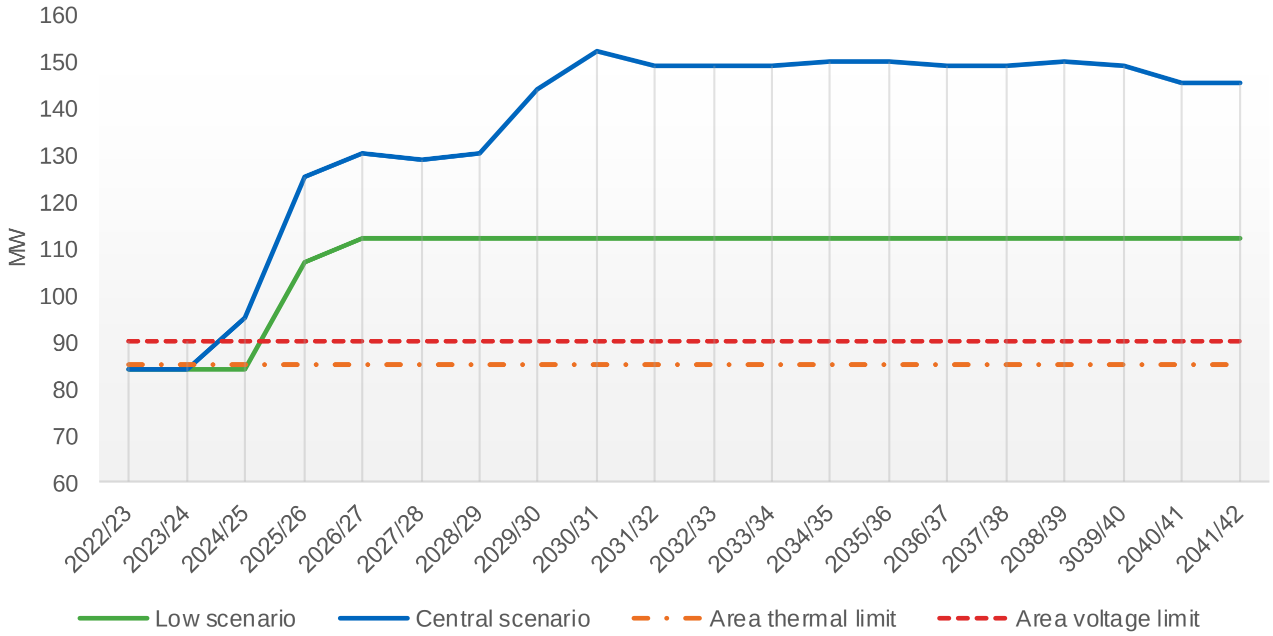
- thermal constraints on line 969 (Tamworth to Gunnedah) under system normal conditions; and
- voltage stability constraints between Gunnedah and Narrabri for a contingent outage of line 969 or 968 (Tamworth to Narrabri).

Figure 3 shows the updated voltage limits for the North West Slopes area considering the maximum demand that can be supplied without resulting in network voltages below 0.9 pu, under system normal and under (N-1) contingency conditions, along with the thermal limit due to the increased demand.

[17] As noted in the PADR, the confidential mining load that drove the high demand forecast in the PSCR (and was the only difference between the central and high demand forecasts at that point in time) is no longer expected to connect.

[18] The development of the gas pipeline linking the Narrabri Gas Project to the existing Moomba to Sydney Pipeline could affect the later stages of the Narrabri Gas Project, See Appendix B for detail on the potential gas pipeline linking the Narrabri Gas Project to the existing Moomba to Sydney Pipeline.

Figure 3: Peak demand forecast with voltage and thermal limits



The voltage stability constraint occurs for a trip of line 969, and is expected by 2024/25 and 2025/26 under the central and low demand forecasts, respectively.

The thermal constraint on line 969 due to the inclusion of stage 1 of the Narrabri Gas Project in 2025/26 can occur during system normal conditions or a contingent outage of line 968 under both demand forecasts when there is limited generation in service in the area to offset the load. It can also occur during system normal conditions from 2029/2030 onwards under the central forecast following the inclusion of stage 2 of the Narrabri Gas Project, even with more generation in service.

The thermal constraint is expected to occur from the inclusion of VCM in 2024/25 along with the Narrabri Coal load growth but can also be temporarily managed by operational measures until stage 1 of the Narrabri Gas Project comes online.

Under the central forecast, the voltage constraints are expected to worsen from 2025/26 onwards. Voltages at Narrabri and Gunnedah would be further outside of the planning criteria set out in Schedule 5.1.4 of the NER for an outage of one of the 132 kV transmission lines supplying Narrabri and Gunnedah from Tamworth (lines 968 or 969).

If action is not taken, voltages in the area will drop to unsustainable levels and voltage collapse could occur in the region following a contingency on line 969 due to insufficient dynamic reactive support in the region under both demand forecasts. This voltage collapse could lead to significant amounts of load being shed throughout the North West Slopes area.

Under both demand forecasts outlined in this PACR, the load increase at the Narrabri substation leads to the firm supply capacity for the transformers at this location being exceeded. This will result in the IPART reliability standard not being met.

2.3.3. The wholesale market modelling has been updated to explicitly model the three key 2022 ISP scenarios

The credible options in the PADR were assessed using a set of market modelling assumptions that were largely based on the 'progressive change' scenario identified by AEMO in the draft 2022 ISP (released in December 2021).[19]

The wholesale market modelling has now been updated in this PACR to:

- explicitly model each of the step-change, progressive change and hydrogen superpower scenarios from the 2022 ISP, adopting the 2021 IASR assumptions; and
- align with the optimal development path and assumptions in the draft 2022 ISP.

Section 6.3 provides further detail on how the market modelling has been undertaken for this PACR, while Appendix D provides an overview of the market simulation exercise undertaken and the key assumptions drawn upon. A separate market modelling report prepared by EY is being released alongside this PACR.

We note that there have been a number of announcements made since the draft 2022 ISP was released regarding the early closure of coal-fired power stations in the NEM. Specifically:

- AGL announced in February 2022 that the Loy Yang A Power Station in Victoria and Bayswater Power Station in NSW will close by at least 2045 and 2033, respectively (three years early than previously indicated);[20] and
- Origin Energy submitted a notice to AEMO in February 2022 for the potential early retirement of Eraring Power Station in August 2025 (seven years early than previously indicated).[21]

The announcements are in addition to an earlier announcement by EnergyAustralia in March 2021 that the Yallourn Power Station in Victoria will close in mid-2028 (four years ahead of schedule).[22]

The wholesale market modelling undertaken as part of this PACR takes account of these updated dates (and draws directly on the latest AEMO generator information database).

2.3.4. Updates to the non-network options (Option 5A and 5B)

We have worked with the proponents of Option 5A and Option 5B (both of which involve network support provided by BESS) to carefully review the proposed timing and cost of each solution. This has resulted in:

- the timing of Option 5A being brought forward by six months from the PADR;
- minor revisions to the cost of Option 5A and Option 5B; and
- elements of the non-network options being resized and re-scoped by proponents.

These options are not considered to be a long-term standalone solution and, instead, will defer or avoid some of the network investment that would otherwise be required.

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[19] We initially modelled the market benefits for the PADR using AEMO's 'steady progress' 2022 ISP scenario, which AEMO noted in the 2021 IASR is 'similar conceptually to the 2020 central scenario'. However, the draft 2022 ISP released on 10 December 2021 stated that the steady progress scenario is no longer relevant, given Australia's commitment to net zero emissions by 2050. We therefore updated the market modelling for the PADR over December 2021 and January 2022 to be based on the progressive change scenario (time would not permit updating to the step-change scenario).

[20] AGL Energy, *ASX and Media Release – 1H22 Results Announcement*, 10 February 2022, at https://cdn-api.markitdigital.com/apiman-gateway/ASX/asx-research/1.0/file/2924-02485194-2A1355883?access_token=83ff96335c2d45a094df02a206a39ff4.

[21] Origin Energy, *Media release – Origin proposes to accelerate exit from coal-fired generation*, 17 February 2022, at https://www.originenergy.com.au/about/investors-media/origin-proposes-to-accelerate-exit-from-coal-fired-generation/.

[22] Energy Australia, *Media release – EnergyAustralia powers ahead with energy transition*, 10 March 2021, at https://www.energyaustralia.com.au/about-us/media/news/energyaustralia-powers-ahead-energy-transition.

In addition, we have conducted an assessment of the technical capacity all non-network options assessed in this PACR (including Option 5C, outlined below) and now consider that the non-network options will be able to address the load growth's thermal and voltage constraints sufficiently until the network between Tamworth and Gunnedah is strengthened in 2029/30.

2.3.5. A new non-network option has been included in the assessment (Option 5C)

In response to a submission made in response to the PADR, a new non-network option has been included in the PACR analysis, 'Option 5C'.

Option 5C uses a BESS to provide a network support service, in a similar way to Option 5A and Option 5B (but with different capacities and/or locations). The details of Option 5C have not been presented in this PACR to preserve the requested confidentiality by the proponent.

As with Option 5A and Option 5B, this option is not considered to be a long-term standalone solution and, instead, will defer or avoid some of the network investment that would otherwise be required. Further information regarding Option 5C is provided in section 4.4 below.

2.3.6. Updated assumptions regarding how BESS components can trade in market services

We have further assessed the ability of BESS components to use their capacity to participate in market services outside of their network support commitments. This covers the three non-network-provided BESS options (i.e. Options 5A, 5B and 5C).

While the PADR adopted a simplifying assumption that these BESS components could use their full capacity to participate in the market,[23] we now assume differing abilities to participate in market services for the BESS components across both any particular year and over time (and, specifically, before and after the network component of these options is commissioned in 2029/30). These assumptions reflect best estimates at this point in time and the specific commercial and operational requirements for BESS components of non-network options will be refined during the commercial negotiations and procurement process following the completion of the RIT-T.

The updated assumptions regarding the capacity to participate market services can be summarised as follows:

- before the network component[24] is commissioned and before the Narrabri Gas Project comes online:
  - full battery capacity is available throughout the year except for in Summer (mid-November to mid-March), where a minor quantity of battery capacity may be required to be reserved.
- before the network component is commissioned but after the Narrabri Gas Project comes online:
  - full battery capacity is available throughout the year except for in Summer and June, where either no battery capacity is available or a quantity of battery capacity is required to be reserved.

[23] This assumption was made at the time of the PADR as a simplifying assumption, and one in favour of the non-network options, in order to test whether these options were expected to be preferred. The PADR outlined that we would be working with proponents to revise this assumption ahead of the PACR (see section 6.4 of the PADR).

[24] Specifically, rebuilding the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit and upgrading the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA.

- after the network component is commissioned:
    - full battery capacity is available throughout the year except for in Summer, where a minor quantity of battery capacity is required to be reserved.

In addition, following the more detailed review of the BESS components' ability to participate outside of their network support commitments, the network owned BESS option (Option 3B) is now also assumed to be able to participate in market services and generate wider wholesale market benefits. However, we note that this is assumed able to occur only after the commissioning of the network components in 2029/30 and is only able to occur outside of the Summer peak period.[25]

The specific energy and capacity that is assumed able to trade in the market for each option has not been presented in this PACR to preserve the confidentiality requested by proponents of these solutions.

2.3.7. Updates to the network options

We have reviewed and, in some cases, updated the timing of the network components of each credible option in light of the updated demand forecasts.

Capital costs for the network options have been revised since the PADR to reflect the change in size of some elements, as well as to reflect current market trends and risks, drawing on the experience of recent projects. The cost of the BESS component in Option 3B has also been updated since the PADR to reflect a proposal by a third-party in response to the PADR.

[25] Consistent with the current transmission ring-fencing guidelines, we have implicitly assumed that we would lease out the spare battery capacity to a third party to provide these contestable services. However, we note that the AER is currently reviewing the transmission ring-fencing guidelines and, specifically, in the case of TNSP-owned batteries, whether the TNSPs should be able to lease excess capacity to third parties (see: AER, *Ring-fencing Guideline Electricity Transmission*, Issues Paper, May 2022, p. 18). The ability of this option to generate these wider wholesale market benefits is therefore subject to the outcome of this review process.

3. Consultation on the PADR

The PADR was released in February 2022 and we subsequently received submissions from seven parties, one of whom submitted two separate submissions.

The two submissions from the same party (Whitehaven Coal) and one other submission (from PIAC) are publicly available and have been published on our website.[26] The remainder of the submitters explicitly requested confidentiality and so the details of these submissions have not been included in this PACR, or on our website.

The main topics that emerged in the submissions were:

- a new non-network option;
- further details regarding an earlier proposed non-network option;
- uncertainty around the demand forecasts;
- a proposal for an alternate conductor technology, that could reduce the network option costs; and
- the appropriateness of the 'high benefits' scenario.

In addition, one of the confidential submitters proposed the use of an alternate conductor technology. We have assessed this option thoroughly as part of preparing the PACR and works for the line 969 double-circuit rebuild, and the 9UH line uprating, now reflect the use (and costs) of this alternate conductor technology proposed in response to the PADR.

The key matters raised in the public submissions are summarised in the following subsections, together with our responses and how the matters raised have been reflected in the PACR assessment. Appendix E provides a summary of all public points raised as part of consultation on the PADR.

3.1. Uncertainty around the demand forecasts

PIAC expressed concerns over demand forecasts being treated as commercial-in-confidence.[27] PIAC also expressed concern regarding using demand forecasts based on regional growth plans, such as the Narrabri SAP, suggesting they are largely aspirational and include targets that are rarely met within intended timeframes.[28]

We understand that there are valid commercial reasons for demand forecasts being kept confidential in RIT-T processes. We note that some of the key loads have made their forecasts public as part of their PADR submission, e.g., Whitehaven Coal's Narrabri Coal Stage 3 Expansion Project. In addition, while not released publicly, the detail regarding all load forecasts has been shared in-confidence with the AER in its role of overseeing the RIT-T and ensuring the efficiency of any ultimately proposed expenditure.

In preparing this PACR, we have engaged further with load proponents on the commitment status for key potential loads. Specifically, we have sought to corroborate the forecasts provided by proponents through having them provide additional information as to how each load is considered to meet the RIT-T criteria for being considered 'committed' or 'anticipated'.

[26] https://www.transgrid.com.au/projects-innovation/north-west-slopes-area-supply
[27] PIAC, p. 1.
[28] PIAC, p. 1.

Whitehaven Coal provided confirmation regarding the intent to proceed with the Narrabri Coal Stage 3 expansion project (which received approval from the Independent Planning Commission on 1 April 2022)[29] and the Vickery expansion project (which has received state and federal approval).[30] Section 2.3.1 above outlines how these two loads have been reflected in the demand forecasts for this PACR.

3.2. Estimating the market benefits of the options

PIAC expressed a view that the high benefits scenario should not be included in the analysis due to unrealistic assumptions.[31] PIAC recommended a 'more realistic' approach of applying 50 per cent weighting to each of the central and low net economic benefits scenarios (and removing the high scenario).[32]

We note that the purpose of using a high benefits (and low benefits) scenario is to test the rankings of options against an extreme bound of plausible economic benefits. Specifically, the three scenarios assessed in this PACR reflect combinations of assumptions that are expected to affect the ranking of the credible options, including the expected wholesale market benefits, in order to comprehensively test the range of net benefits that can be expected from the credible options. We discuss the role of the three scenarios further in section 5.1, including how the parameters varied across the scenarios relate to those that are expected to have the potential to impact the ranking of the options as well as how the variation in the VCR comes directly from the AER.

We consider that this approach allows for a more robust test of the preferred option compared with adopting individual sensitivity tests, since multiple variables are changed at once. This approach to constructing scenarios has been adopted across a range of RIT-Ts where wholesale market benefits are expected to form a lower proportion of the overall estimated net benefit. We note that the high benefits and low benefits scenarios are largely symmetric in terms of the assumptions drawn upon and we consider that removing one (as PIAC have suggested) would bias the analysis.

We have weighted each of the scenarios for this RIT-T based on the draft 2022 ISP weightings for the underlying wholesale market scenarios. Specifically, we have given each scenario a weighting based on the proportion its weighting in the draft 2022 ISP makes up of the cumulative 96 per cent given to these three scenarios (as outlined in section 5.2), which has had the effect of reducing the weighting applied to the high scenario from the PADR. We have also carefully considered the results in each scenario in section 7 and investigated a sensitivity that applies the scenario weights from the PADR (see section 7.5.3).

29 Whitehaven Coal, p. 1 (Narrabri Coal submission).
30 Whitehaven Coal, p. 1 (Vickery expansion project submission).
31 PIAC, p. 1.
32 PIAC, p. 2.

4. Credible options assessed

This PACR assesses both network and non-network options.

Each of the credible network options requires the installation of a third 60 MVA 132/66 kV transformer at Narrabri due to the firm supply capacity of the existing transformers at this location being exceeded under both demand forecasts and to ensure the reliability standard set by IPART is met for Narrabri in the short-term.

Aside from the new 132/66 kV transformer at Narrabri, the credible network options assessed differ in the near-term by where, how and when new capacity is added to the North West Slopes region. In particular, there are three broad types of credible option assessed that centre on:

- uprating the existing line 969 from Tamworth to Gunnedah (Option 1A and Option 1B);
- installing new single or double circuit transmission lines between Tamworth and Gunnedah (Option 2A, Option 2B, Option 2C and Option 2D); and
- rebuilding the existing line 969 from Tamworth to Gunnedah to be a double circuit line (Option 3A, Option 3B and Option 3C).

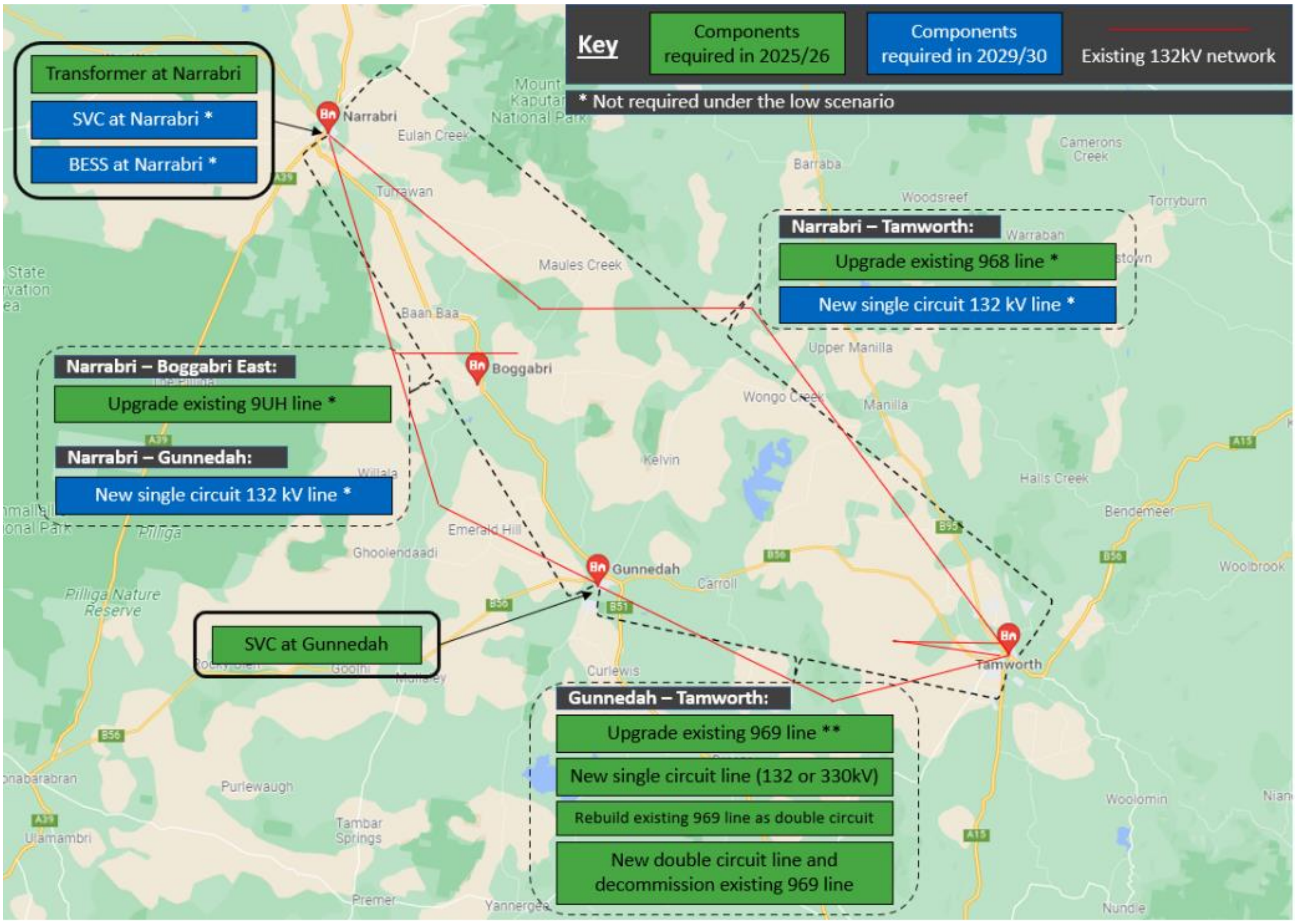
Most credible options include the provision of dynamic reactive support at Narrabri provided by an SVC or grid-scale BESS. Two options (Option 2C and Option 3C) involve a new transmission line between Gunnedah and Narrabri as an alternative to dynamic reactive support and the upgrade to the 9UH line.

Figure 4 below illustrates the various components that make up the credible network options. Specifically, it shows the technology and location of the components that can assist with both the short-term and longer-term voltage support required. While the credible options reflect different combinations of these components, we note that not all components can be coupled together to form credible options (and the earlier components can impact the choice of the later component(s)).

All locations shown in the figure below, and all figures in this section, have been included purely for illustrative purposes and are not intended to denote specific locations or line routes.

Importantly, each of the options involves two potential stages of investment, depending on the option and scenario. These are shown in the figure below as the components required in 2025/26 (in green) and the components required in 2029/30 (in blue). The individual option sections below detail the specific timing assumed for each stage of each option under the two demand forecasts.

Figure 4: Various components the credible network options involve



*** While the upgrade of the 969 line between Gunnedah and Tamworth to 160 MVA is required under the low and central scenario for Options 1A and 1B, it is only required under the central scenario and to 135 MVA for Options 2A, 2B, 2D and 4.*

While there have been no material changes to the network options since the PADR, the non-network options considered in the PACR assessment have been refined to reflect:

- submissions to the PADR, resulting in the timing of Option 5A being brought forward by six months from the PADR, minor revisions to the cost of Option 5A and Option 5B and the inclusion of a third non-network option (Option 5C); and
- elements of the non-network options being resized and rescoped following additional information provided by proponents.

In addition, as outlined in section 4.4, the non-network solutions have been modelled in terms of their ability to efficiently defer or avoid the rebuilding of line 969 as a double-circuit line when the Narrabri Gas Project comes online, which is part of the preferred network option (Option 3A). Non-network options are not able to avoid or defer the need for the initial third transformer required at Narrabri under this option since capacity is required there immediately to ensure the reliability standard set by IPART is met at Narrabri. The non-network options therefore reflect a combination of an initial non-network component and a third Narrabri transformer in all scenarios, followed by a deferred rebuilding of line 969 as a double-circuit line and upgrading the 9UH line between Narrabri and Boggabri North in the central and high scenarios when the Narrabri Gas Project comes online.

Table 4-1 below summarises each of the credible options assessed in the PACR. All options are considered to meet the identified need from a technical, commercial, and project delivery perspective.[33]

While all potential components of each option are shown in Table 4-1, some of the later components are not required over the assessment period for the low demand forecast and are only relevant for the central demand forecast (in the later years of the assessment period). The timing of the initial components for all options has been fixed across the two demand forecasts (since these components effectively need to be committed to now to ensure commissioning in time under the central forecast), while the timing of the later components varies by forecast depending on when they are required (since they do not yet need to be committed to). The individual option sections below detail the specific timing assumed for each component of each option under the two demand forecasts.

While some component costs in Table 4-1 below include land costs and biodiversity offset costs, they have not been broken out separately to contain the table. However, the NPV model released alongside the PACR separates out these elements.

Table 4-1: Summary of the credible options

Option	Description	Estimated capex ($2020/21)
Uprating the existing line 969 from Tamworth to Gunnedah		
1A	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA	• $51 million
	• Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah substation	• $18 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
	• Upgrade the existing 968 line between Tamworth 330 and Narrabri substations to a rating of at least 160 MVA	• $149 million
	• Install a 132 kV +60 MVAr -20 MVAr SVC at Narrabri	• $20 million
1B	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA	• $51 million
	• Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah substation	• $18 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million

33 As per clause 5.15.2(a) of the NER.

Option	Description	Estimated capex ($2020/21)
	• Build a new 132 kV line between Tamworth 330/132 kV and Narrabri 132/66 kV substations	• $160 million
New single or double circuit transmission lines between Tamworth and Gunnedah		
2A	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new single circuit 160 MVA 132 kV line between Tamworth 330 kV and Gunnedah.	• $73 million
	• Upgrade the existing 969 line to a rating of 135 MVA	• $51 million
	• Upgrade the 9UH line to a rating of 100 MVA	• $28 million
	• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	• $20 million
2B	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new double circuit 132 kV line between Tamworth 330 kV and Gunnedah, each circuit rated at 160 MVA. Decommission the existing 969 transmission line	• $89 million
	• Upgrade the 9UH line to a rating of 100 MVA	• $28 million
	• Installation of a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	• $20 million
2C	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new single circuit 160 MVA 132 kV line between Tamworth 330 kV and Gunnedah	• $73 million
	• Upgrade the existing 969 line to a rating of 135 MVA	• $51 million
	• Build a new single circuit 132 kV line between Narrabri and Gunnedah	• $106 million
2D	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new single circuit 330 kV line between Tamworth 330 kV and Gunnedah operated at 132 kV, rated at least 160 MVA	• $159 million
	• Upgrade the existing 969 line to a rating of 135 MVA	• $51 million
	• Upgrade the 9UH line to a rating of 100 MVA	• $28 million
	• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	• $20 million
Rebuilding the existing line 969 from Tamworth to Gunnedah to be a double circuit line		
3A	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
	• Install a 132 kV +60 MVAr (capacitive) -20 MVAr (inductive) SVC at Narrabri substation	• $20 million
3B	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million

Option	Description	Estimated capex ($2020/21)
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
	• Install a 50 MW (50 MWh) BESS at Narrabri 132 kV	• Confidential
3C	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Build a new single circuit 132 kV line between Narrabri and Gunnedah	• $106 million
Combination of non-network solutions with the top-ranked network option (Option 3A)		
5A	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Install a BESS at Gunnedah 132 kV as a network support service	• Confidential
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
5B	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Install a BESS near Gunnedah 132 kV as a network support service	• Confidential
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
5C	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Install a BESS at Gunnedah 132 kV as a network support service	• Confidential
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million

Capital costs for the network options have been revised since the PADR to reflect the change in size of some elements, as well as to reflect current market trends and risks, drawing on the experience of recent projects. In addition, works for the line 969 double-circuit rebuild, and the 9UH line uprating, now reflect the use (and costs) of an alternate conductor technology proposed in response to the PADR.

All network options are assumed to have annual operating and maintenance costs equal to approximately one per cent of their capital costs (excluding biodiversity offset and land costs).

The remainder of this section provides further detail on each of the credible options assessed. It also outlines further options that have been considered but not progressed (and the reasons why).

Appendix C provides the indicative ultimate layouts, via line diagrams, for all elements of the options.

4.1. Option 1 – Uprating the existing line 969 from Tamworth to Gunnedah

This option involves uprating the existing line 969 and the two variants test different line augmentations and dynamic reactive support levels at Narrabri and Gunnedah.

The scope of the various elements for Option 1A and Option 1B is shown in Table 4-1 above.

Table 4-2 summarises the optimal assumed timing for each component under the two different demand forecasts investigated.

Table 4-2: Summary of the assumed timing for each component of Option 1A and Option 1B

Component	Expected timing (low)	Expected timing (central)
Option 1A		
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA • Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah Substation	2025/26	2025/26
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	N/A	2028/29
• Upgrade the existing 968 line between Tamworth 330 and Narrabri substations to a rating of at least 160 MVA	N/A	2027/28
• Install a 132 kV +60 MVAr -20 MVAr SVC at Narrabri	N/A	2029/30
Option 1B		
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA • Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah Substation	2025/26	2025/26
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	N/A	2026/27
• Build a new 132 kV line between Tamworth 330/132 kV and Narrabri 132/66 kV substations	N/A	2029/30

Figure 5 below illustrates the type and location of the key elements for Option 1A and Option 1B.

Figure 5: Overview of the key elements in Option 1A and Option 1B

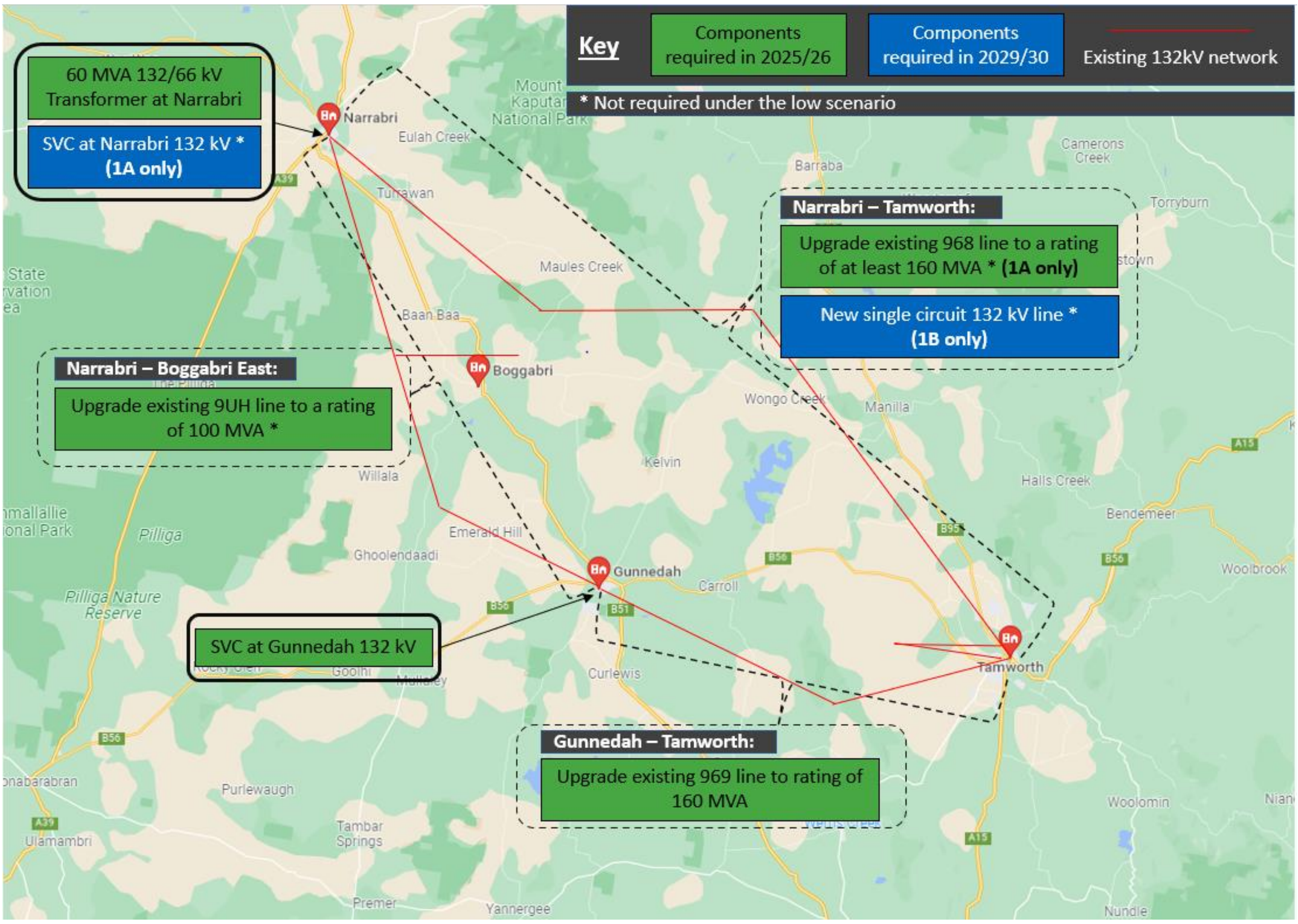


Table 4-3 summarises the expected construction time for each component.

Table 4-3: Summary of the expected construction time for each component of Option 1A and Option 1B

Component	Expected construction time[34]
Option 1A	
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA • Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah Substation	36 months
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA • Upgrade the existing 968 line between Tamworth 330 and Narrabri substations to a rating of at least 160 MVA	65 months
• Install a 132 kV +60 MVAr -20 MVAr SVC at Narrabri	37 months

[34] Please note that all expected construction times are presented as beginning from Design Gate 1 (DG1), which would commence approximately 1 month after the PACR.

Option 1B	
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA • Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah Substation	36 months
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	48 months
• Build a new 132 kV line between Tamworth 330/132 kV and Narrabri 132/66 kV substations	69 months

4.2. Option 2 – New single or double circuit transmission lines between Tamworth and Gunnedah

This option involves installing new single or double circuit transmission lines between the Tamworth 330 kV substation and Gunnedah with the variants testing different line augmentations.

The scope of elements for Option 2A, Option 2B, Option 2C and Option 2D is shown in Table 4-1 above.

Table 4-4 summarises the optimal assumed timing for each component under the two different demand forecasts investigated.

Table 4-4: Summary of the assumed timing for each component of Options 2A-2D

Component	Expected timing (low)	Expected timing (central)
Option 2A		
• Install a third 60 MVA 132/66 kV transformer at Narrabri	2025/26	2025/26
• Build a new single circuit 160 MVA 132 kV line between Tamworth 330 kV and Gunnedah.	2028/29	2028/29
• Upgrade the existing 969 line to a rating of 135 MVA	N/A	2027/28
• Upgrade the 9UH line to a rating of 100 MVA	N/A	2028/29
• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	N/A	2029/30
Option 2B		
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Decommission the existing 969 transmission line	2025/26	2025/26
• Build a new double circuit 132 kV line between Tamworth 330 kV and Gunnedah, each circuit rated at 160 MVA	2028/29	2028/29
• Upgrade the 9UH line to a rating of 100 MVA	N/A	2027/28
• Installation of a 132 kV +50 MVAr -20 MVAr SVC at Narrabri.	N/A	2029/30
Option 2C		
• Install a third 60 MVA 132/66 kV transformer at Narrabri	2025/26	2025/26
• Build a new single circuit 160 MVA 132 kV line between Tamworth 330 kV and Gunnedah	2028/29	2028/29

• Upgrade the existing 969 line to a rating of 135 MVA	N/A	2027/28
• Build a new single circuit 132 kV line between Narrabri and Gunnedah	N/A	2029/30
Option 2D		
• Install a third 60 MVA 132/66 kV transformer at Narrabri	2025/26	2025/26
• Build a new single circuit 330 kV line between Tamworth 330 kV and Gunnedah operated at 132 kV, rated at least 160 MVA	2028/29	2028/29
• Upgrade the existing 969 line to a rating of 135 MVA • Upgrade the 9UH line to a rating of 100 MVA	N/A	2027/28
• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	N/A	2029/30

Figure 6 below illustrates the type and location of the key elements for Options 2A-2D.

Figure 6: Overview of the key elements in Options 2A-2D

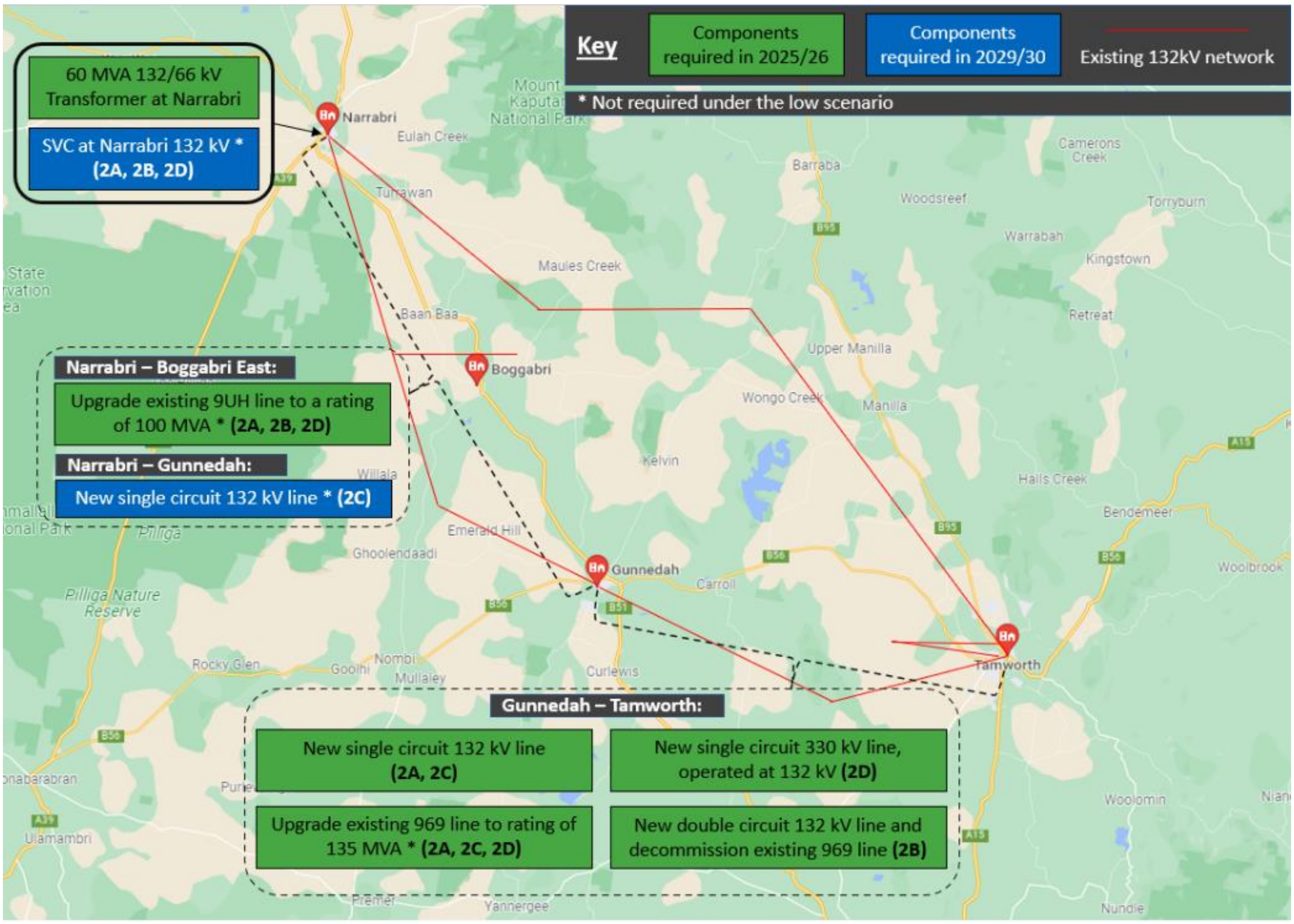


Table 4-5 summarises the expected construction time for each component.

Table 4-5: Summary of the expected construction time for each component of Options 2A-2D

Component	Expected construction time
Option 2A	
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Build a new single circuit 160 MVA 132 kV line between Tamworth 330 kV and Gunnedah.	62 months
• Upgrade the existing 969 line to a rating of 135 MVA • Upgrade the 9UH line to a rating of 100 MVA	70 months
• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	37 months
Option 2B	
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Build a new double circuit 132 kV line between Tamworth 330 kV and Gunnedah, each circuit rated at 160 MVA • Decommission the existing 969 transmission line	64 months
• Upgrade the 9UH line to a rating of 100 MVA	57 months
• Installation of a 132 kV +50 MVAr -20 MVAr SVC at Narrabri.	37 months
Option 2C	
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Build a new single circuit 160 MVA 132 kV line between Tamworth 330 kV and Gunnedah	62 months
• Upgrade the existing 969 line to a rating of 135 MVA	57 months
• Build a new single circuit 132 kV line between Narrabri and Gunnedah	61 months
Option 2D	
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Build a new single circuit 330 kV line between Tamworth 330 kV and Gunnedah operated at 132 kV, rated at least 160 MVA	61 months
• Upgrade the existing 969 line to a rating of 135 MVA • Upgrade the 9UH line to a rating of 100 MVA	70 months
• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	37 months

4.3. Option 3 – Rebuilding the existing line 969 from Tamworth to Gunnedah to be a double circuit line

This option involves rebuilding line 969 to be a double circuit line with the three variants testing different line augmentations and dynamic reactive support levels. It represents a brownfield development and so is in line with Transgrid's preference to maintain social licence by utilising existing easements where possible.

The scope of the elements for Option 3A, Option 3B and Option 3C is shown in Table 4-1 above.

Table 4-6 summarises the optimal assumed timing for each component under the two different demand forecasts investigated.

Table 4-6: Summary of the assumed timing for each component of Options 3A-3C

Component	Expected timing (low)	Expected timing (central)
Option 3A		
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	2025/26	2025/26
• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah Substations as a double circuit	2025/26	2025/26
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	N/A	2027/28
• Install a 132 kV +60 MVAr (capacitive) -20 MVAr (inductive) SVC at Narrabri Substation	N/A	2029/30
Option 3B		
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	2025/26	2025/26
• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah Substations as a double circuit	2025/26	2025/26
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	N/A	2027/28
• Install a 50 MW (50 MWh) BESS at Narrabri 132 kV	N/A	2029/30
Option 3C		
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	2025/26	2025/26
• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah Substations as a double circuit	2025/26	2025/26
• Build a new single circuit 132 kV line between Narrabri and Gunnedah	N/A	2029/30

As outlined in section 2.3.6, following a more detailed review of the BESS components' ability to arbitrage outside of their network support commitments, the network owned BESS option (Option 3B) is now assumed to be able to arbitrage (to a small degree) and generate wider wholesale market benefits.

In addition, the cost of the BESS in Option 3B has been updated since the PADR to reflect a proposal from a proponent in response to the PADR.

Figure 7 below illustrates the type and location of the key elements for Options 3A-3C.

Figure 7: Overview of the key elements in Options 3A-3C

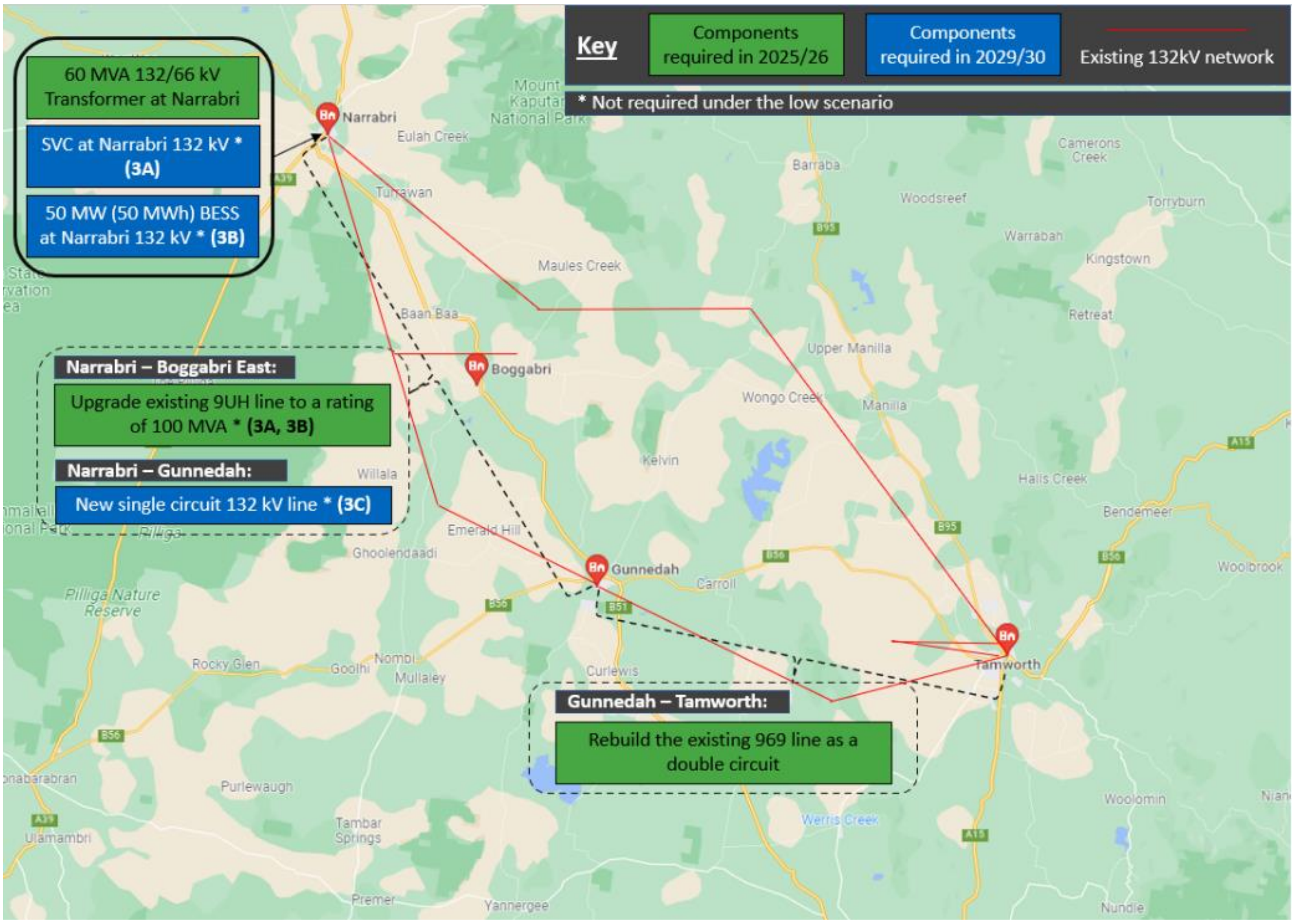


Table 4-7 summarises the expected construction time for each component.

Table 4-7: Summary of the expected construction time for each component of Options 3A-3C

Component	Expected construction time[35]
Option 3A	
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation • Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah Substations as a double circuit	44 months
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	56 months
• Install a 132 kV +60 MVAr (capacitive) -20 MVAr (inductive) SVC at Narrabri Substation	37 months
Option 3B	
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	44 months

[35] Please note that all expected construction times are presented as beginning from Design Gate 1 (DG1), which would commence approximately 1 month after the PACR.

• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah Substations as a double circuit	
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	56 months
• Install a 50 MW (50 MWh) BESS at Narrabri 132 kV	39 months
Option 3C	
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation • Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah Substations as a double circuit	44 months
• Build a new single circuit 132 kV line between Narrabri and Gunnedah	61 months

4.4. Option 5 – Non-network options

The three non-network options (Option 5A, Option 5B and Option 5C) use BESS to provide a network support service. These options vary by the size, number and location of the BESS. The details of these options have not been presented in this PACR to preserve the requested confidentiality by proponents.

We have assessed the technical feasibility of these options further since the PADR and consider, at this stage, that they are technically feasible and are able to address the identified need in a timely manner. We note that the connection process following the RIT-T will further assess and confirm the specific technical details of connection for the preferred option.

The table below specifies the minimum network support requirements for non-network options at Gunnedah (132 kV) that Transgrid will seek from proponents. Several parties have proposed larger solutions that provide other market services, in addition to providing this network support service.

Year	MW – Thermal constraint	MVAr – Voltage constraint
2026	50 MW	20 MVAr
2029	55 MW	20 MVAr
2030	57 MW	20 MVAr

The non-network solutions are not considered to be long-term standalone solutions and, instead, defer or avoid the rebuilding of line 969 as a double-circuit line and upgrading the 9UH line between Narrabri and Boggabri North, as part of the preferred network option (Option 3A). Non-network options are not able to avoid or defer the need for the initial third transformer required at Narrabri under this option since capacity is required there immediately to address the IPART reliability standard for the Narrabri area.

Table 4-8 summarises the optimal assumed timing for each component under the two different demand forecasts investigated.

Table 4-8: Summary of the assumed timing for each component of Option 5A, Option 5B and Option 5C

Component	Expected timing (low)	Expected timing (central)
Option 5A		
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	2025/26	2025/26
• Install a BESS at Gunnedah 132 kV as a network support service	Confidential	Confidential
• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	N/A	2029/30
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	N/A	2029/30
Option 5B		
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	2025/26	2025/26
• Install a BESS near Gunnedah 132 kV as a network support service	Confidential	Confidential
• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	N/A	2029/30
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	N/A	2029/30
Option 5C		
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	2025/26	2025/26
• Install a BESS at Gunnedah 132 kV as a network support service	Confidential	Confidential
• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	N/A	2029/30
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	N/A	2029/30

4.5. Options considered but not progressed

We have also considered whether other options could meet the identified need. The reasons these options were not progressed are summarised in Table 4-9.

Table 4-9: Options considered but not progressed

Option	Reason(s) for not progressing
Capacitor banks/ switched capacitors	Not technically feasible. Our studies show that due to the expected extensive load growth in the Narrabri and Gunnedah areas, adding a number of additional capacitor banks or switched capacitors in the area is a non-credible solution since step changes in voltages caused by their switching would lead to voltage excursions outside NER requirements. This remains unchanged since the PSCR.

Option	Reason(s) for not progressing
Connection to the New England Transmission Infrastructure (NETI) project	This option was presented in the PSCR and involves connecting to a potential new non-prescribed project in the Gunnedah area called the NETI (a potential 330 kV transmission line between Tamworth 330/132 kV substation and a new 330 kV substation between Tamworth and Gunnedah with the aim of unlocking new renewable energy investment in the New England area of NSW). While ARENA has provided funding to Transgrid to assess the feasibility of an innovative commercial model to develop the NETI,[36] we removed the option of connecting to the potential NETI from the PADR assessment given the uncertainty involved (particularly around the timing). We considered this option not technically feasible at the PADR stage of the RIT-T and do not consider this to have changed since (e.g., no connection enquiry has been made).

[36] https://arena.gov.au/projects/transgrid-new-england-renewable-energy-zone/

5. Ensuring the robustness of the analysis

The investments considered as part of this RIT-T involve long-lived assets, and it is important that the recommended preferred option does not depend on a narrow view of future outcomes, given that the future is inherently uncertain.

Uncertainty is captured under the RIT-T framework through the use of reasonable scenarios, which reflect different assumptions about future market development, and other factors that are expected to affect the relative market benefits of the options being considered. The adoption of different scenarios tests the robustness of the RIT-T assessment to different assumptions about how the energy sector may develop in the future.

The robustness of the outcome is also investigated through the use of sensitivity analysis in relation to key input assumptions. We have also identified the key factors driving the outcome of this RIT-T and sought to identify the 'threshold value' for these factors, beyond which the outcome of the analysis would change.

5.1. The assessment considers three 'reasonable scenarios'

The RIT-T is focused on identifying the top ranked credible option in terms of expected net benefits. However, uncertainty exists in terms of estimating future inputs and variables (termed future 'states of the world').

To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to determine a weighted ('expected') net benefit.[37] It is this 'expected' net benefit that is used to rank credible options and identify the preferred option.

The credible options have been assessed under three scenarios as part of this PACR assessment, which differ in terms of the key drivers of the estimated net market benefits.

The three scenarios are characterised as follows:

- a 'low net economic benefits' scenario, involving a number of assumptions that gives a lower bound , conservative estimate of the present value of net economic benefits;
- a 'central' scenario based on a central set of variable estimates and reflects the most likely scenario; and
- a 'high net economic benefits' scenario that reflects a set of assumptions selected to investigate an upper bound of net economic benefits

The table below summarises the specific key variables that influence the net benefits of the options under each of the scenarios considered.

[37] The AER RIT-T Application Guidelines explicitly refer to the role of scenarios as the primary means of taking uncertainty into account. See: AER, *RIT-T Application Guidelines*, December 2018, p. 42.

Table 5-1: Summary of scenarios

Variable	Central	Low net economic benefits	High net economic benefits
Network capital costs	Base estimate	Base estimate + 25%	Base estimate - 25%
Non-network capital costs	Base estimate	Base estimate + 25%	Base estimate - 25%
Demand	Central demand forecast (as outlined in section 2.3.3)	Low demand forecast (as outlined in section 2.3.3)	Central demand forecast (as outlined in section 2.3.3)
New renewable generation in the area	In-service and committed generators from Appendix B.	All in-service, committed and advanced generators from Appendix B.	In-service and committed generators from Appendix B.
Wholesale market benefits estimated	EY estimated based on the step-change 2022 ISP scenario	EY estimated based on the progressive change 2022 ISP scenario	EY estimated based on the hydrogen superpower 2022 ISP scenario
VCR[38]	$46.88/kWh	$32.82/kWh	$60.95/kWh
Discount rate	5.50%	7.50%	1.96%

While wholesale market benefits (and so the ISP scenarios) are relevant to this RIT-T, we note that they are only one element that is expected to affect the ranking of the credible options and only affect the net benefits of four of the twelve options (i.e., those involving BESS, as outlined in section 2.2). This differs from a RIT-T for an actionable ISP project where the impact on the wholesale market (and so the ISP scenarios) are the primary driver of the ranking of the options and typically affect the net benefits of all options assessed.

The scenarios developed for this RIT-T therefore include the three 2022 ISP scenarios, as well as the following variables that are expected to affect the ranking of the options:

- network and non-network capital costs – given the cost differences between the options, the underlying drivers of capital costs are expected to have a bearing on which option is ultimately preferred;
- demand – the primary source of market benefit for this RIT-T is avoided unserved energy in the North West Slopes region and so the scenarios have been constructed to investigate two different demand forecasts (as outlined in section 2.3.1);
- new renewable generation in the area – the amount of renewable generation in the area has an impact on the amount of unserved energy that is expected to be avoided by each of the credible options;
- VCR – estimates of the VCR are crucial to determining the value of avoided unserved energy but are subject to uncertainty and so, in addition to using the central VCR estimates (which are based on the AER estimates), we have also reflected VCR estimates in the scenarios that are 30 per cent lower and 30 per cent higher, consistent with the AER's specified +/- 30 per cent confidence interval.[39]

[38] The VCRs have been updated since the PADR to reflect the updated underlying demand forecasts, i.e., the load that would be affected under the base case. However, we note that this update has had only a minor impact on the estimated VCRs.
[39] AER, *Values of Customer Reliability – Final Report on VCR values*, December 2019, p. 84.

- discount rate – the discount rate directly affects the trade-off between costs now and benefits in the future and we have reflected three different discount rates in the scenarios (as outlined in section 6.5).

The three scenarios assessed in this PACR (summarised in Table 5-1 above) reflect combinations of the above assumptions, as well as wholesale market benefits estimated for each of the three 2022 ISP scenarios, in order to comprehensively test the range of net benefits that can be expected from the credible options. We consider that this approach allows for a more robust test of the preferred option since multiple variables are changed at once. In addition, to the scenario testing, we also undertake sensitivity testing, which varies one variable at a time to test the robustness of the preferred option to alternate individual assumptions regarding that variable alone (typically in relation to the most likely, central scenario).

5.2. Weighting the reasonable scenarios

We have weighted each of the scenarios for this RIT-T based on the draft 2022 ISP weightings for the underlying wholesale market scenarios. Specifically, we have given each scenario a weighting based on the proportion its weighting in the draft 2022 ISP makes up of the cumulative 96 per cent given to these three scenarios, i.e.:[40]

- 52 per cent to central scenario (based on the step-change scenario in the ISP);
- 30 per cent to the low benefits scenario (based on the progressive change scenario in the ISP); and
- 18 per cent to the high benefits scenario (based on the hydrogen superpower scenario in the ISP).

These weights differ from those used in the PADR[41] and reflect the fact that the wholesale market benefits have now been estimated across the three 2022 ISP scenarios, whereas the PADR only estimated wholesale market benefits for the progressive change scenario (as outlined in section 2.3.3).

While the above weights have been applied to weight the estimated market benefits and identify the preferred option across scenarios (illustrated in section 7), we have also carefully considered the results in each scenario in section 7. In addition, we have undertaken a sensitivity using the weightings adopted in the PADR (see section 7.5.3).

5.3. Sensitivity analysis

In addition to the scenario analysis, we have also considered the robustness of the outcome of the cost benefit analysis through undertaking a range of sensitivity testing.

The range of factors tested as part of the sensitivity analysis in this PACR are:

- the assumed timing of both the network and non-network components;
- alternate commercial discount rate assumptions; and
- different scenario weightings.

The results of the sensitivity tests are discussed in section 7.5.

[40] We note also that these weights align with the weights AEMO have recommended be applied to the VNI West RIT-T (where the same three scenarios are to be considered) in the draft 2022 ISP released in December 2021 – see: AEMO, *Draft 2022 Integrated System Plan*, December 2021, p. 69.
[41] The PADR weighted the central scenario at 50 per cent (given it is considered the most likely since it is based primarily on a set of expected assumptions), with the other two scenarios being weighted equally with 25 per cent each.

The above list of sensitivities focuses on the key variables that could impact the identified preferred option.

6. Estimating the market benefits

As outlined in section 2, the key benefit expected from the options is avoided involuntary load shedding in the North West Slopes area. In addition, for the two options that involve a non-network component, there are also expected to be benefits from anticipated changes in the wholesale market outcomes going forward.

The RIT-T requires categories of market benefits to be calculated by comparing the 'state of the world' in the base case where no action is undertaken, with the 'state of the world' with each of the credible options in place, separately. The 'state of the world' is essentially a description of the National Electricity Market (NEM) outcomes expected in each case, and includes the location and quantity of load in North West Slopes, as well as the type, quantity and timing of future generation investment.

This section outlines how each of the broad categories of market benefit have been estimated.

EY has undertaken the wholesale market modelling component of the PACR assessment. Appendix D provides additional detail on the wholesale market modelling undertaken by EY. We are also publishing a separate modelling report prepared by EY alongside this PACR that provides greater detail on the modelling approach and assumptions, to provide transparency to market participants.

6.1. Base case

Consistent with the RIT-T requirements, the assessment undertaken in the PACR compares the costs and benefits of each option to a base case 'do nothing' option. The base case is the (hypothetical) projected case if no action is taken.

Under the base case, where the longer-term constraints associated with load growth in the North West Slopes area is unresolved, significant interruption of supply to loads in the area under normal and contingency conditions would be expected, due to voltage limitations and/or voltage collapse in the local supply network.

While this is not a situation we plan to encounter, and this RIT-T has been initiated specifically to avoid it, the assessment is required to use this base case as a common point of reference when estimating the net benefits of each credible option.

We have not quantified the avoided expected involuntary load shedding after 2028/29 as part of the PACR analysis since each option will address all constraints equally from then and avoid the same amount of unserved energy thereafter. Quantifying the full extent of avoided involuntary load shedding under each option after 2028/29 will therefore not assist in identifying the preferred option under the RIT-T. Moreover, the levels of unserved energy under the base case are expected to be extremely high and so will dwarf the other quantified costs and benefits if this approach is not applied (e.g., we estimate that these will exceed $550 million/year by 2029/30 under the central demand forecasts and increase thereafter).

Importantly, we have taken into account all avoided expected involuntary load shedding for the years in which the options differ in respect of how much involuntary load shedding will occur, ie, prior to 2028/29. This captures the *differences* in the expected avoided involuntary shedding *between* options as well providing an indication of the extent of these benefits overall.

We consider this is consistent with the approach adopted in other RITs, the Energy Networks Australia RIT-T Handbook[42] and advice provided to the AER.[43]

6.2. Avoided involuntary load shedding in the North West Slopes area

We have run system studies to estimate the Expected Unserved Energy (EUE) in the North West Slopes area under each of the base cases and each of the credible options.

The avoided EUE for each option has been valued using the estimated VCRs published by the AER.[44] Specifically, we have developed a load-weighted VCR estimate for the central scenario using the AER VCR values for the customer groups relevant to the region. We have then applied VCR estimates that are 30 per cent lower and 30 per cent higher for the low and high scenarios, respectively, consistent with the AER's specified +/- 30 per cent confidence interval.[45]

The EY market modelling has also quantified the impact of changes in involuntary load shedding *outside* of the North West Slopes area associated with the implementation of each credible option via the time sequential modelling component of the market modelling. Specifically, the modelling estimates the MWh of EUE in each hourly trading interval over the modelling period, and then applies the AER VCRs to quantify the estimated value of avoided EUE outside of the North West Slopes area for each option. However, these estimated changes in EUE are not expected to be material for any of the credible options.

6.3. Options replacing line 969 would avoid future wood pole replacement costs

Under the base case, we expect to replace aged wood pole structures on line 969 within the next twenty years. The expected timing of this work is between 2026/27 and 2044/45 and is the same as assumed in the PADR.

For all options that replace line 969 with a new line (i.e., Option 2B, Option 3A, Option 3B, Option 3C, Option 5A, Option 5B and Option 5C), this expenditure is able to be avoided and so provides an economic benefit in the analysis. However, given the majority of the expenditure is expected in the last few years of the assessment period, it is found to be a minor source of benefit for these options.

6.4. Wholesale market benefits

As outlined in section 2.2, four of the credible options assessed in this PACR involve the use of BESS and are able to use a portion of their capacity to dispatch to the wholesale market. Dispatching to the wider market can offset more costly generation that would otherwise operate in the NEM and thus provide wider wholesale market benefits on top of the avoided unserved energy that all options provide.[46]

These wider benefits have been estimated by way of wholesale market modelling conducted by EY. Appendix D summarises the key variables under the three scenarios modelled that influence the wholesale market benefits of the options. Additional detail on the wholesale market modelling undertaken, including the assumptions and methodologies, can be found in the accompanying EY market modelling report.

42 ENA, *RIT-T Economic Assessment Handbook for non-ISP RIT-Ts*, Version 2.0, 26 October 2020, p. 51.
43 Biggar, D., *An Assessment of the Modelling Conducted by TransGrid and Ausgrid for the 'Powering Sydney's Future' Program*, May 2017, pp. 12-16.
44 The VCR values have been taken from the most recent VCR update from the AER, i.e.: AER, *Annual update – VCR review final decision – Appendices A – E*, December 2021.
45 AER, *Values of Customer Reliability – Final Report on VCR values*, December 2019, p. 84.
46 While the other credible network options (i.e., the solely network options) will provide additional system strength to the North West Slopes region, we do not consider there to be material wholesale market benefits associated with these options, as outlined in section 2.3.

Table 6-1 below summarises the specific categories of wholesale market benefit under the RIT-T that have been modelled as part of this PACR.

Table 6-1: Categories of wholesale market benefit under the RIT-T that have been modelled as part of this PACR

Market benefit	Overview
Changes in costs for other parties in the NEM	This category of market benefit is expected where credible options result in different investment patterns of generators and large-scale storage across the NEM, compared to the base case. The capital and operating costs associated with the BESS components have been captured in the PACR assessment as a cost to other parties, reflecting that this is an additional resource cost to the NEM that would not be incurred if we did not sign a network support agreement with the proponents for these options (as these projects are not already committed or anticipated). This is consistent with the AER's revised guidance on the treatment of non-network options.[47] However, the market benefits associated with these options operating outside of times needed for network support (in particular their impact on dispatch costs and generation investment), compared with the base case in which those batteries are not in place, has also been captured as part of the modelling for each of these options.
Changes in fuel consumption in the NEM	This category of market benefit is expected where credible options result in different patterns of generation and storage dispatch across the NEM, compared to the base case. Where non-network options are able to trade in the wholesale market outside of their network support commitments, this may result in a different pattern of generation dispatch.
Changes in network losses	The time sequential market modelling has taken into account the change in network losses that may be expected to occur as a result of the implementation of each of the credible options, compared with the level of network losses which would occur in the base case, for each scenario. The benefit of changes to network losses is captured within the wholesale market modelling of dispatch cost benefits of avoided fuel costs and changes to voluntary and involuntary load shedding. The reduction in network losses between the base case and the options is considered immaterial for the options considered in this PACR but reduces both the energy to be produced by fossil fuel generators to account for the losses, and a reduction in new capacity that has to be built to supply demand, particularly during peak periods.
Differences in unrelated transmission costs	This benefit category relates to the costs of intra-regional transmission investment associated with the development of REZ that could be avoided if a credible option is pursued. AEMO has identified a number of REZ in various NEM jurisdictions as part of the ISP and has included allowances for transmission augmentations that it considers would be required to develop those REZ. While the credible options being considered in this RIT-T can in theory assist with allowing the development of some of these REZ without the need for additional intra-regional transmission investment (or with less of it), it is in a very minor way and this category of market benefit is not considered significant for this RIT-T.

[47] AER, *Guidelines to make the Integrated System Plan actionable*, Final decision, August 2020, p. 26.

Market benefit	Overview
Changes in involuntary load curtailment (outside of the North West Slopes area)	This market benefit involves quantifying the impact of changes in involuntary load shedding associated with the implementation of each relevant credible option via the time sequential modelling component of the market modelling. Specifically, the modelling estimates the MWh of unserved energy (USE) in each trading interval over the modelling period, and then applies a Value of Customer Reliability (VCR, expressed in $/MWh) to quantify the estimated value of avoided USE for each option. We have adopted the AER VCRs to quantify the estimated value of avoided EUE for the purposes of this assessment. This category of market benefit has been found to be relatively small within the market modelling. This is due to there not being a material difference in the quantity of involuntary load shedding outside of the North West Slopes area between each option and the base case.
Changes in voluntary load curtailment	Voluntary load curtailment is when customers agree to reduce their load once wholesale prices in the NEM reach a certain threshold. Customers usually receive a payment for agreeing to reduce load in these circumstances. Where the implementation of a credible option affects wholesale price outcomes, and in particular results in wholesale prices reaching higher levels in some trading intervals than in the base case, this may have an impact on the extent of voluntary load curtailment. This class of market benefit has been found to be relatively low within the market modelling, reflecting that the level of voluntary load curtailment is not significantly different between the option cases and the base case.

6.5. General modelling parameters adopted

The RIT-T analysis spans a 20-year assessment period from 2022/23 to 2041/42. This period begins and ends a year later than the PADR and reflects the passage of time since that document was released.

Where the capital components of the credible options have asset lives extending beyond the end of the assessment period, the NPV modelling includes a terminal value to capture the remaining asset life. This ensures that the capital cost of long-lived options over the assessment period is appropriately captured, and that all options have their costs and benefits assessed over a consistent period, irrespective of option type, technology or asset life. The terminal values are calculated as the undepreciated value of capital costs at the end of the analysis period and can be interpreted as a conservative estimate for benefits (net of operating costs) arising after the analysis period.

A real, pre-tax discount rate of 5.50 per cent has been adopted as the central assumption for the NPV analysis presented in this PACR, consistent with the assumptions adopted in 2021 Inputs, Assumptions and Scenarios (IASR). The RIT-T also requires that sensitivity testing be conducted on the discount rate and that the regulated weighted average cost of capital (WACC) be used as the lower bound. We have therefore tested the sensitivity of the results to a lower bound discount rate of 1.96 per cent,[48] and an upper bound discount rate of 7.50 per cent (i.e., the upper bound proposed for the 2022 ISP[49]).

[48] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM, see: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausnet-services-determination-2022%E2%80%9327/final-decision

[49] AEMO, *2021 Inputs, Assumptions and Scenarios Report*, July 2021, p. 105.

6.6. Classes of market benefit not considered material

The NER requires that all categories of market benefit identified in relation to the RIT-T are included in the RIT-T assessment, unless the TNSP can demonstrate that a specific category (or categories) is unlikely to be material in relation to the RIT-T assessment for a specific option.[50]

Competition benefits have not been estimated for any of the options since they are not considered material in the context of this RIT-T. This RIT-T is focussed on efficiently meeting the required reliability standards in the North West Slopes area and, while some options are expected to generate a level of wholesale market benefits, it is not considered sufficient to affect the competitiveness of generator bidding behaviour in any region of the NEM.

Option value is likely to arise in a RIT-T assessment where there is uncertainty regarding future outcomes, the information that is available is likely to change in the future, and the credible options considered are sufficiently flexible to respond to that change. The credible options outlined in this PACR exhibit flexibility in terms of how they can be developed and we have captured the option value of this flexibility implicitly through their components having different assumed timings across the scenarios. We consider this consistent with the AER guidance on the treatment of option value and consider that a wider option value modelling exercise would be disproportionate to any option value that may be identified for this specific RIT-T assessment.

The options are also not expected to have a material impact on ancillary services costs in the NEM. Specifically, each of the options have been designed to resolve the voltage issues on the network and so solve the expected FCAS issues in an identical manner. The options that involve BESS components are not expected to be able to sell services into the FCAS market (given they will be resolving the voltage issues).

[50] NER clause 5.16.1(c)(6).

7. Net present value results

This section outlines the results of the economic assessment we have undertaken of the credible options.

Due to the confidentiality requested by the proponents of the non-network solutions, we are only able to present the overall *net* market benefits of Option 5A, Option 5B and Option 5C (i.e., the present value of the aggregate market benefits estimated less the present value of the aggregate costs).

The accompanying market modelling report prepared by EY provides additional detail in terms of the modelled wholesale market impacts for each option. Neither this PACR nor the accompanying market modelling report provide the estimated wholesale market benefits of the non-network options in dollar terms, in order to preserve the confidentiality of the options assessed. The full analysis has been provided in-confidence to the AER as part of their role in overseeing the RIT-T.

All figures of the same type in this section have been presented on the same scale (unless otherwise stated) in order to highlight the differences across scenarios.

7.1. Central scenario

The central scenario reflects our central view of key underlying assumptions and is considered the most likely scenario in terms of the net market benefits for each of the options. These assumptions include central demand forecasts, network and non-network cost estimates, VCR and commercial discount rate estimates. This scenario also includes EY's market modelling of the wholesale market benefits for the BESS options based on the 'step-change' scenario used in the 2022 ISP.

Under these assumptions, two of the options involving non-network solutions in the short-term (i.e., Option 5B and Option 5C) are preferred over the solely network options. This is primarily due to these options being able to be commissioned approximately one to two years before the network options, which allows them to avoid substantial additional unserved energy.

Option 5B is the top-ranked option overall, with estimated net benefits that are approximately $16 million (3 per cent) greater than Option 5C and $45 million (8 per cent) greater than Option 3A.[51] The third non-network option, Option 5A, is found to have net market benefits that are $20 million (3 per cent) below Option 3A.

Option 3A is the top-ranked purely network option. While it has the second lowest expected total cost of the network options, in present value terms, it can avoid a substantial amount of unserved energy one to two years earlier than the lowest cost network option (Option 2B) and so provides greater benefits.[52]

Figure 8 shows the overall estimated net benefit for each option under the central scenario. All figures of this format in the PADR show the top-ranked options in green, and the other options in blue.

[51] Please note that while this sentence, and all sentences of this type in the PACR, presents the percentage differences between options, these percentages are calculated excluding the avoided expected unserved energy after 2028/29 as it is common to all options (and so does not assist in identifying the preferred option), as outlined in section 6.1. These percentages should therefore be interpreted as being based on net benefit numbers that exclude the superfluous unserved energy, as opposed to being based on the *total* expected net benefit numbers.

[52] The present value of all capex and opex of Option 3A under this scenario is $101 million, which compares to $93 million for Option 2B.

Figure 8: Summary of the estimated net benefits under the central scenario

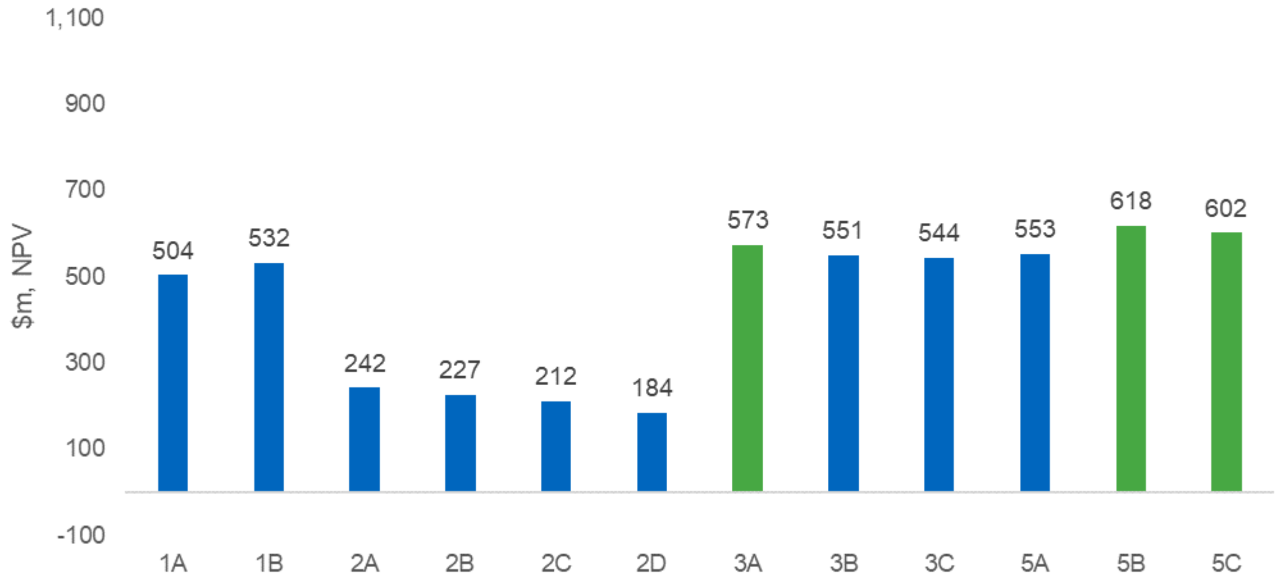
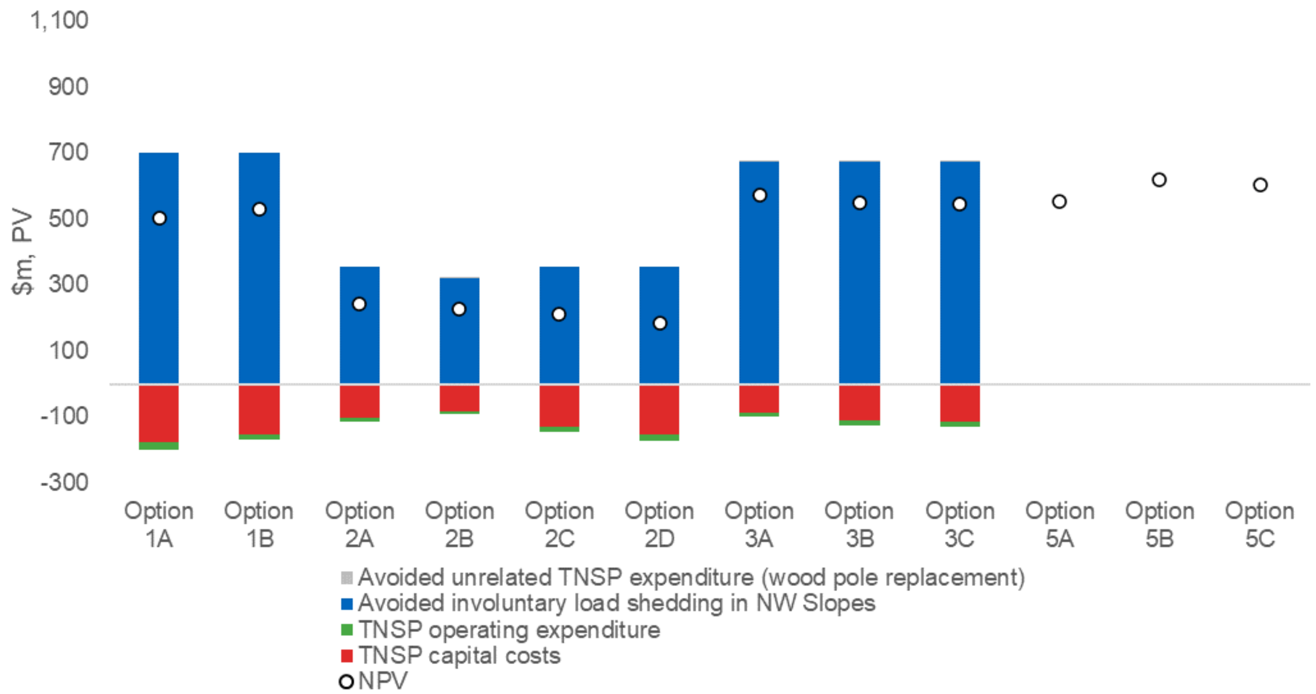


Figure 9 shows the composition of estimated net benefits for each option under the central scenario. Only the net numbers are shown for Option 5A, Option 5B and Option 5C in order to protect the confidentiality of these options. The level of wholesale market benefits for Option 3B (the Transgrid-owned BESS option) has also been redacted from this figure (and all figures of this type in the PACR) to avoid any inferences being made regarding the costs (or benefits) of the non-network options.

Figure 9: Breakdown of estimated net benefits under the central scenario



The wholesale market modelling for the options involving BESS finds that the primary source of benefit is from avoided and deferred capex for new generation/storage (making up approximately 80 per cent of the wholesale market benefits). However, the wholesale market benefits are relatively minor in the overall assessment for this scenario and only contribute between 6 and 8 per cent of the total estimated gross market benefits for the three non-network BESS options (and less than 1 per cent for Option 3B, which has a grid-owned BESS).

7.2. Low net economic benefits

The low net economic benefits scenario reflects a number of assumptions that give a lower bound and conservative estimate of net present value of net economic benefits. These assumptions include the low demand forecast, high network and non-network cost estimates, low VCR and a high commercial discount rate estimate. This scenario also includes EY's market modelling of the wholesale market benefits for the BESS options based on the 'progressive change' scenario used in the 2022 ISP.

Under these assumptions, Option 1A and Option 1B are top-ranked but are only marginally ahead of Option 3B (by $4.3 million) and Option 5B ($10.9 million). Option 5C and Option 5A are $27.8 million and $43 million behind Option 1A and Option 1B, respectively.

Most options are found to have net costs under this scenario, meaning that they are not preferred over the base case 'do nothing' option, which is driven by the significantly lower avoided unserved energy under this scenario compared to the central scenario. However, we note that these net costs are only marginal and, if we did not apply the approach to removing unserved energy (outlined in section 6.1) that has no bearing on the ranking of the options, all options would be found to have significantly positive net benefits.

Figure 10 shows the overall estimated net benefit for each option under the low economic benefits scenario.

Figure 10: Summary of the estimated net benefits under the low economic benefits scenario

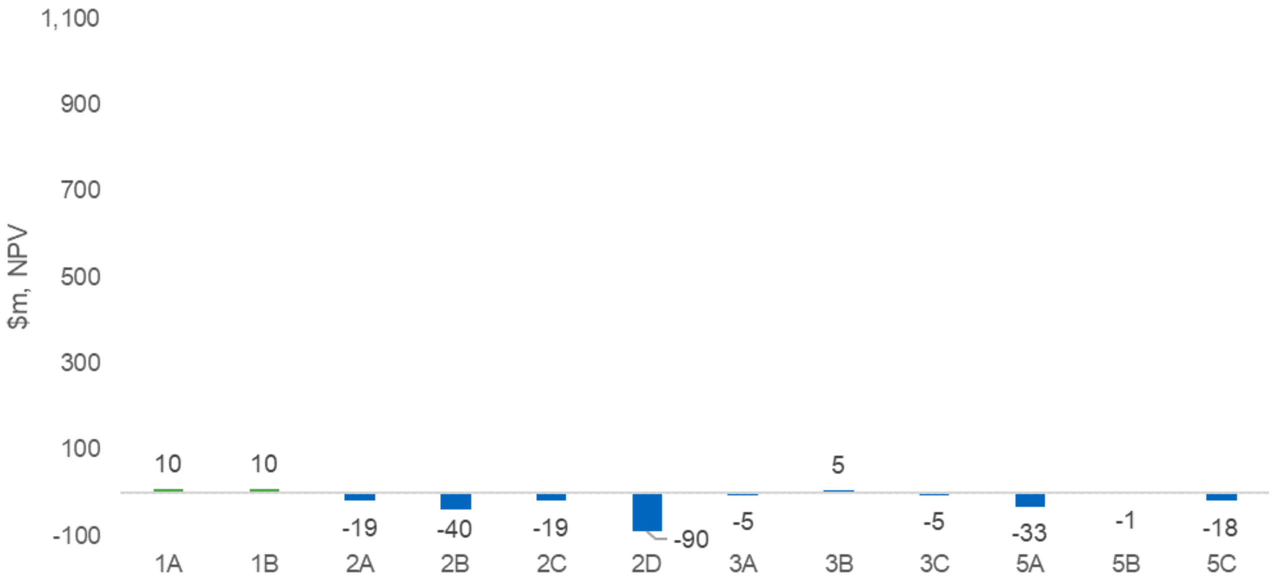
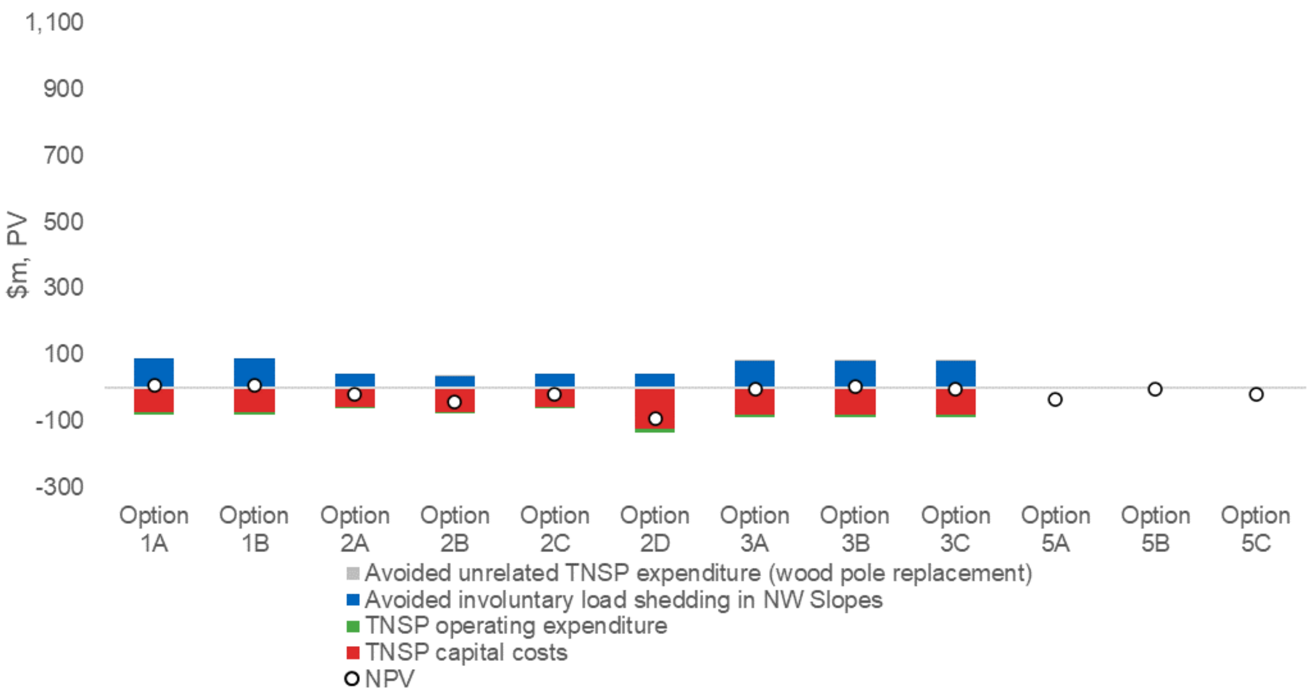


Figure 11 shows the composition of estimated net benefits for each option under this scenario. Only the net numbers are shown for Option 5A, Option 5B and Option 5C to protect the confidentiality of these options.

Figure 11: Breakdown of estimated net benefits under the low economic benefits scenario



As under the central scenario, the wholesale market benefits are comprised almost exclusively of avoided and deferred capex for new generation/storage (making up approximately 100 per cent of the wholesale market benefits for this scenario). However, in contrast to the central scenario, the wholesale market benefits make up between 41 and 47 per cent of the total estimated gross benefit for the three non-network BESS options under the low scenario (and 11 per cent for Option 3B, which has a grid-owned BESS). We note however that if the full amount of expected unserved energy was included in this scenario (i.e., not the approach outlined in section 6.1), these percentages would fall substantially.

While the low net economic benefits scenario includes EY's market modelling of the wholesale market benefits for the BESS options based on the 'progressive change' scenario used in the 2022 ISP, since this is considered the most conservative scenario of the three 2022 ISP scenarios modelled, the wholesale market modelling finds that the progressive change scenario has marginally greater expected wholesale market benefits from the BESS options compared to the other two scenarios. This is due to the wholesale market modelling finding that significant new open cycle gas turbine (OCGT) capacity can be avoided with the BESS options for the progressive change scenario, compared to the other two scenarios.[53] However, we note that the variation in the level of wholesale market benefits estimated across the three scenarios is minor and considered immaterial to the overall PACR conclusion.

7.3. High net economic benefits

The high net economic benefits scenario reflects assumptions that give an upper bound estimate of net present value of net economic benefits. These include the central demand forecast (as outlined in section 5.1), low network and non-network cost estimates, high VCR and a low commercial discount rate estimate.

[53] The relatively high level of new OCGT investment expected under the base case for the progressive change scenario, which is able to be avoided by the BESS options, is due to the interaction between the retirement of Eraring in 2025-26, the timing of Humelink in 2035-36 (compared to 2027-28 and 2028-29 for the other two scenarios) as well as the relatively relaxed carbon constraint.

This scenario also includes EY's market modelling of the wholesale market benefits for the BESS options based on the 'hydrogen superpower' scenario used in the 2022 ISP.

Under these assumptions, as with the central scenario, two of the options involving non-network solutions in the short-term (i.e., Option 5B and Option 5C) are preferred over the solely network options. This is again due to these options being able to be commissioned approximately one to two years before the network options, which allows them to avoid substantial additional unserved energy.

Option 5B is the top-ranked option overall, with estimated net benefits that are approximately $20 million (2 per cent) greater than Option 5C and $107 million (11 per cent) greater than Option 3A. The third non-network option, Option 5A, is found to have net market benefits that are effectively equal ($7 million/0.7 per cent greater) to Option 3A under this scenario.

As with the central scenario, Option 3A is the top-ranked purely network option. While it has the second lowest expected total cost of the network options, in present value terms, under this scenario, it can avoid a substantial amount of unserved energy one to two years earlier than the lowest cost network option (Option 2B), and so has greater net benefits.[54]

Figure 12 shows the overall estimated net benefit for each option under the high economic benefits scenario.

Figure 12: Summary of the estimated net benefits under the high economic benefits scenario

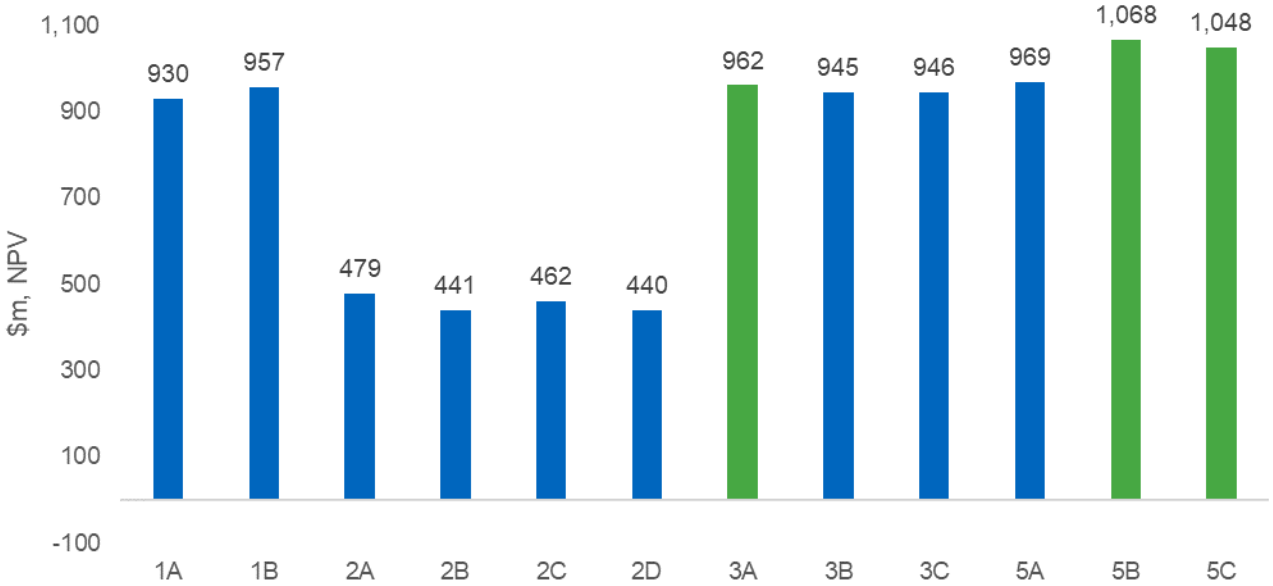
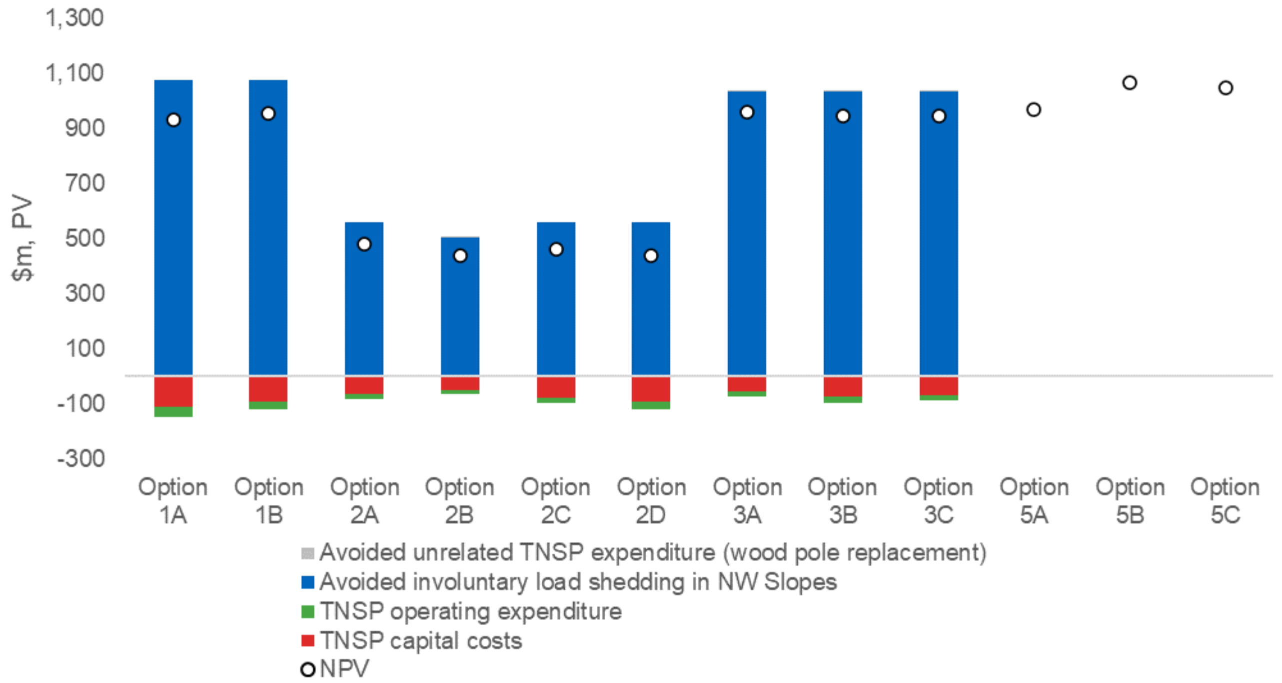


Figure 13 shows the composition of estimated net benefits for each option under this scenario. Only the net numbers are shown for Option 5A, Option 5B and Option 5C in order to protect the confidentiality of these options.

[54] The present value of all capex and opex of Option 3A under this scenario is $72 million, which compares to $64 million for Option 2B.

Figure 13: Breakdown of estimated net benefits under the high economic benefits scenario



As under the central scenario, the wholesale market benefits are comprised almost exclusively of avoided and deferred capex for new generation/storage (making up between 87 and 95 per cent of the wholesale market benefits for these options under this scenario). The wholesale market benefits are also minor in the overall assessment for this scenario and only contribute between 5 and 6 per cent of the total estimated gross market benefits for the three non-network BESS options (and 0.7 per cent for Option 3B, which has a grid-owned BESS).

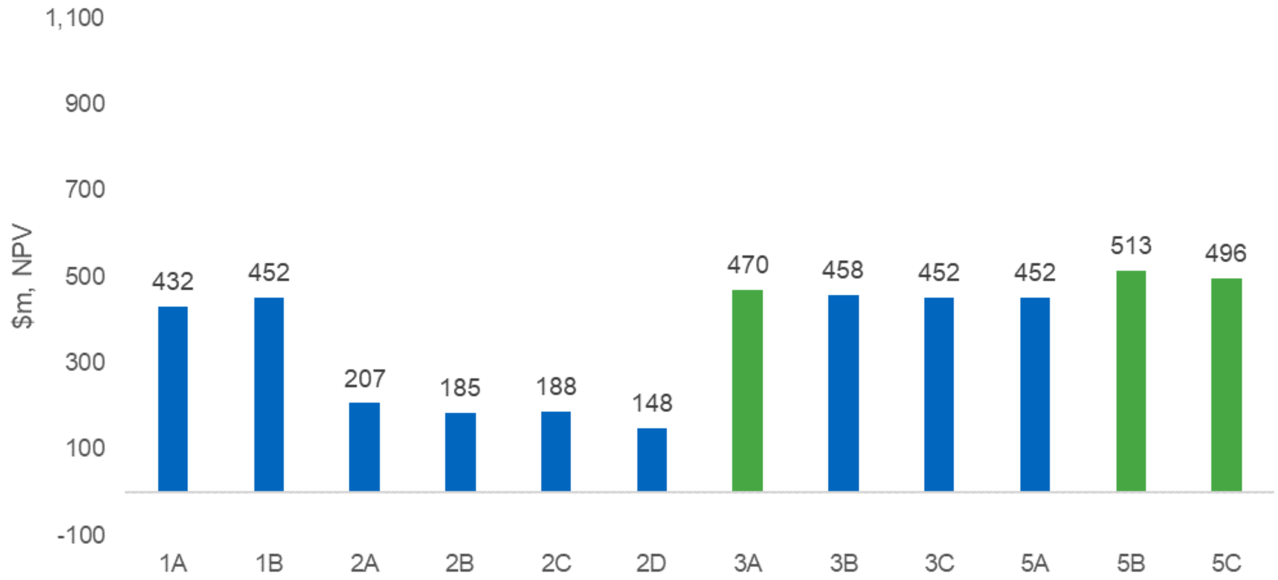
7.4. Weighted net benefits

Figure 14 shows the estimated net benefits for each of the credible options weighted across the three scenarios investigated (and discussed above).

Under the weighted outcome, two of the options involving non-network solutions in the short-term (i.e., Option 5B and Option 5C) are preferred over the solely network options.

Option 5B is the top-ranked option overall, with net benefits that are approximately $17 million (3 per cent) greater than the second ranked option (Option 5C) and $43 million (9 per cent) greater than the top-ranked solely network option (Option 3A). The third non-network option, Option 5A, is found to have net market benefits that are $18 million (4 per cent) below Option 3A.

Figure 14: Summary of the estimated net benefits, weighted across the three scenarios



While the low scenario yields different top-ranked options, we do not consider this material to the overall conclusion of the RIT-T (i.e., that the non-network options are preferred) given the quantity of unserved energy expected to be avoided across the scenarios. The low scenario would need to be given an unreasonably high weighting in order to change the conclusion of this PACR. Specifically, we find that the low scenario would need to be given a weighting of approximately 74 per cent in order for either Option 5B or Option 5C to be ranked below any of the purely network. [55]

Overall, a key determinant of the overall preferred option is the assumed build times, and ultimate commissioning dates, of each of the credible options since options that can be commissioned sooner allow for substantial amount of unserved energy to be avoided. This is investigated further in section 7.5.1 below.

7.5. Sensitivity analysis

In addition to the scenario analysis, we have also considered the robustness of the outcome of the cost benefit analysis through undertaking a range of sensitivity testing.

The range of factors tested as part of the sensitivity analysis in this PACR are:

- the assumed timing of both the network and non-network components;
- alternate commercial discount rate assumptions; and
- different scenario weightings.

Each of the sensitivity tests undertaken in this PACR are discussed in the sections below.

We note that the scale in some of the figures in this section is smaller than their counterparts in earlier sections in order to show the impact of these sensitivities more clearly.

[55] We note that this weighting does not change if we value all avoided unserved energy in the assessment, i.e., if we do not apply the approach of removing unserved energy in the later years of the assessment outlined in section 6.1 of this PACR.

We have not presented a standalone sensitivity below on changes in the underlying network capital costs of the credible options since the low (high) net economic benefits scenario already reflects 25 per cent higher (lower) capital costs for the network elements and we do not expect network costs to vary by more than this amount.

We have also not presented a standalone sensitivity below on changes in the underlying non-network capital costs of the credible options since the low (high) net economic benefits scenario already reflects 25 per cent higher (lower) capital costs for the non-network elements.

7.5.1. Assumed timing of the network and non-network components

As outlined in section 7.4, a key determinant of the overall preferred option in this RIT-T assessment is the assumed build times, and ultimate commissioning dates, of each of the credible options, since options that can be commissioned sooner allow for substantial amount of unserved energy to be avoided.

While the commissioning dates for each option have been estimated using our, and third party (where relevant), best endeavours at this point in time, we have also investigated a range of sensitivities that relax these assumptions to see how the overall conclusion of the assessment is affected.

The table below investigates the effects of assuming earlier commissioning dates for the top-ranked solely network option (Option 3A) as well as assuming later commissioning dates for the top-ranked options involving non-network components (Option 5B and Option 5C). Specifically, Table 7-1 shows the net market benefits under various alternate timing assumptions, with red text denoting the top-ranked option (and any other option within 5 per cent of the top-ranked option).

Table 7-1: Alternate timing sensitivities ($m, NPV), weighted

	Option 3A	Option 5B	Option 5C
Core result	470	513	496
Option 3A one year forward	522	513	496
NNO one year delay	470	516	499
NNO two year delay	470	424	408
Option 3A forward and NNO delay	522	516	499

Red text denotes the preferred option and any option within 5 per cent of the preferred option

While the table above shows that bringing forward Option 3A by one year results in it having effectively the same net benefits as Option 5B and Option 5C, we do not consider this feasible and, at most, consider this option could be expedited by six months.

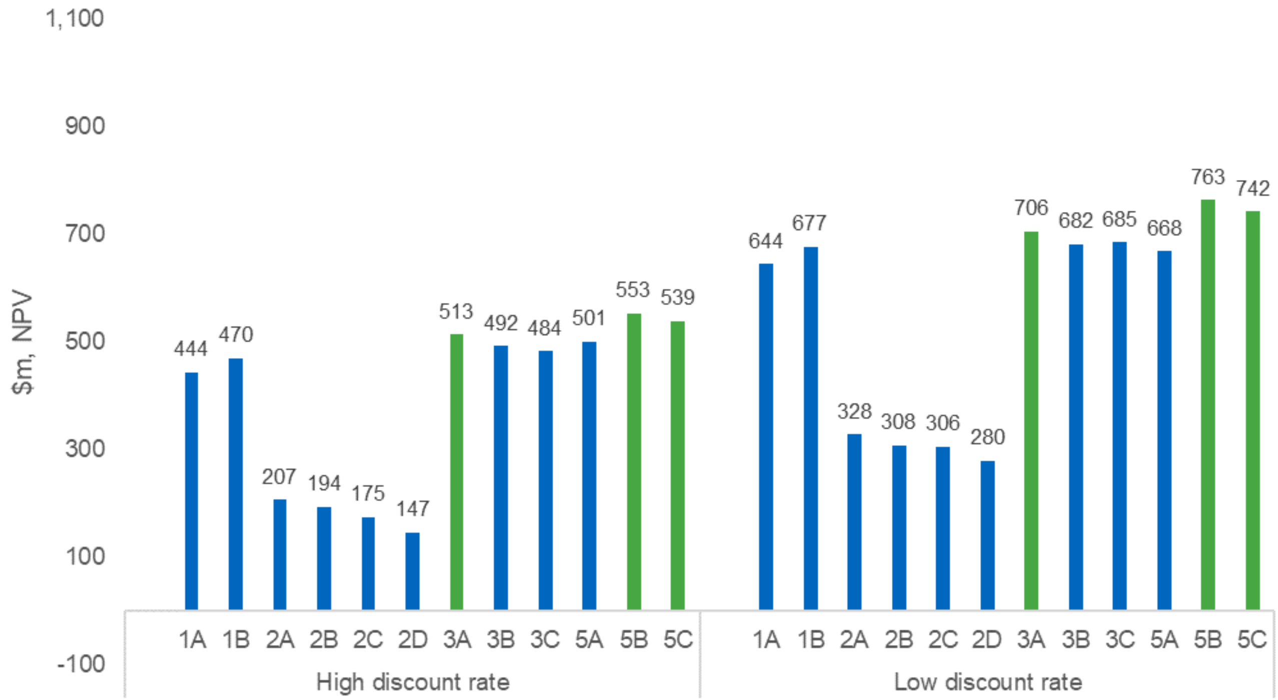
The table above also shows that Option 5B and Option 5C still remain ranked marginally above Option 3A if they were to be deferred by a year. This result is driven by the additional year of discounting for the BESS capital costs marginally outweighing the avoided unserved energy at the start of the assessment period. However, we note that a further year delay would severely decrease the estimated net benefits of these options (due to the significant unserved energy in the base case for that year) and result in Option 3A being uniquely preferred.

7.5.2. Commercial discount rate assumptions

Figure 15 illustrates the sensitivity of the central results to different discount rate assumptions in the NPV assessment. In particular, it illustrates two tranches of net benefits estimated for each credible option – namely:

- a high discount rate of 7.50 per cent; and
- a low discount rate of 1.96 per cent.

Figure 15: Impact of different assumed discount rates, central scenario



Neither sensitivity changes the finding that the non-network options are preferred over the network options, or that Option 5B is the top-ranked option. In addition, neither sensitivity changes the finding that Option 3A is the preferred network option.

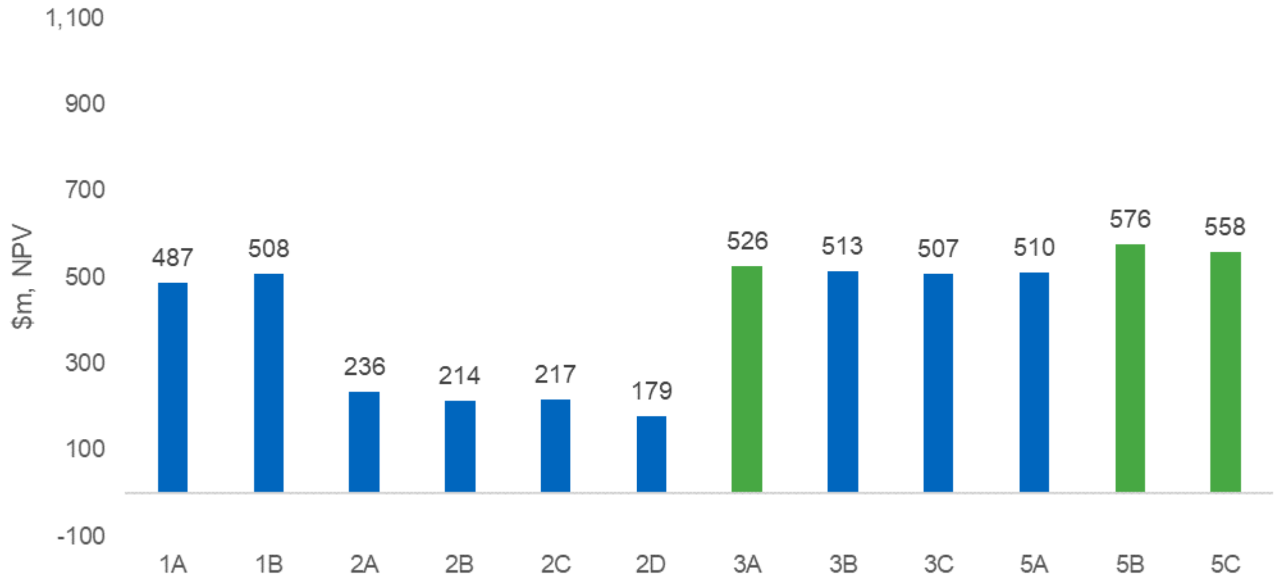
We further find that there is no realistic discount rate that would result in Option 3A being preferred over Option 5B (the discount rate would need to exceed 35 per cent).

7.5.3. Different scenario weightings

We have investigated a sensitivity that applies the scenario weights applied in the PADR assessment, i.e., weighting the 'low benefits' and 'high benefits' scenarios equally at 25 per cent each (as opposed to 30 per cent and 18 per cent, respectively) and the central scenario at 50 per cent (since it is comprised of the 'most likely' set of assumptions).

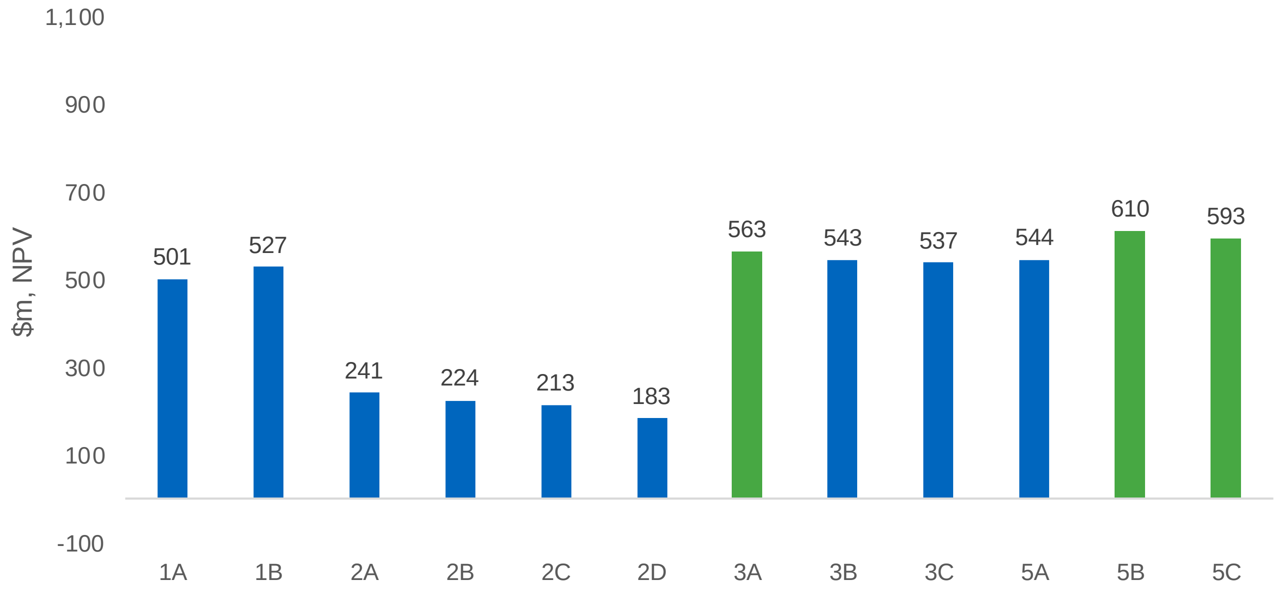
If the scenario weightings from the PADR are applied, the rankings of the top three options do not change. The net benefits of Option 5B and Option 5C are both projected to increase by approximately $62 million, while the net benefits of Option 3A are expected to increase by approximately $56 million. The net benefits of all other options increases by between $28 and $59 million.

Figure 16: Weighted NPV results using scenario weightings from the PADR



We have also investigated a sensitivity that applies a small (5 per cent) weighting to each of the high and low scenarios in light of a submission querying the 25 per cent weighting to these scenarios. This sensitivity finds that the rankings of the top three options do not change. Relative to the core results, the net benefits of Option 5B and Option 5C are expected to increase by $96 million and $97 million respectively, while the net benefits of Option 3A are expected to increase by approximately $94 million.

Figure 17: Weighted NPV results using a 5 per cent weighting for the low and high scenarios



8. Conclusion

The preferred option identified in this PACR involves a non-network solution provided through a BESS at the Gunnedah 132 kV substation and the installation of a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation in the near-term. It also involves the rebuilding of the existing 969 line between the Tamworth 330 kV and Gunnedah substations as a double circuit line and upgrading the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA over the longer-term, depending on outturn demand forecasts.

The proposals of two separate third party non-network BESS proponents have been found to be ranked effectively equal in the PACR assessment. These options are referred to as Option 5B and Option 5C in the PACR, and reflect the proposed BESS component followed by the network investment outlined above. These options are found to deliver approximately $513 million and $496 million in net benefits, respectively, relative to the 'do nothing' base case on a weighted basis, which compares to $470 million for the preferred solely network option (Option 3A).[56] The proposal of the third BESS proponent (assessed as Option 5A) has been found to deliver lower net benefits than these two options but to effectively be ranked equally with Option 3A.

We will now enter into a competitive procurement process and commercial negotiations with non-network proponents for a network support contract and seek to put in place a contract with one of these parties. We consider these negotiations should involve all proponents involved in the RIT-T process (i.e., including Option 5A, which has lower estimated net benefits than the other two non-network options) and potentially others who are able to provide the same kind of solution within the required timeframe, since the timing of when BESS can be implemented is critical to which solution is ultimately preferred (and may be able to be refined through the negotiation process). In addition, we consider that having more parties involved in this process will ensure that the network support costs paid for by consumers are as efficient as possible.

Notwithstanding the above, we consider that if either of the following two events occur, they would likely constitute a 'material change in circumstances' (i.e., under clause 5.16.4(z3) of the NER):

1. None of the non-network proponents being able to commit to having the BESS in place to provide network support by a date that ensures that option continues to be considered as the top-ranked option under the RIT-T; or

2. Transgrid not being able to finalise a network support contract with any of the proponents that is expected to be accepted as prudent and efficient by the AER.

Should either (or both) of these events occur, we would seek an exemption from the AER under clause 5.16.4(z3) of the NER to avoid having to reapply the RIT-T. Specifically, we consider that, should either of the above events occur, then the analysis presented in this PACR demonstrates that Option 3A (i.e., the top ranking solely network option) should then be considered the preferred option under this RIT-T.

We consider this approach provides sufficient confidence that Transgrid will be able to progress an option to ensure the externally-imposed regulatory obligations and service standards this RIT-T is designed to meet are met at an efficient cost level without having to re-do the RIT-T. We note that re-doing the RIT-T would take significant time, which would compromise the reliability of supply to customers in the North West Slopes area and ultimately likely cost all NSW electricity customers more in the long-run.

[56] Option 3A includes an additional network component to Options 5A-5C, as well as earlier investment in some components.

We note that the Rules regarding a 'material change in circumstances', and the ability to include a 'decision rule' in a PACR, is currently being considered by the Australian Energy Market Commission.[57] In the event that the NER change following this PACR, we would consider the events above to constitute two elements of a decision rule for ultimately determining the preferred option for this RIT-T.

We will update stakeholders when we consider that the network support agreement for one of these options is sufficiently certain, or at the point we determine there has been a material change in circumstances and that the investment should be progressed as a solely network option (i.e., Option 3A) (i.e., when we would submit an exemption to the AER from having to reapply the RIT-T).

As stated in our revenue proposal for the 2023-2028 period,[58] we will include the preferred option identified through the RIT-T in our augmentation expenditure forecast in our Revised Revenue Proposal for the forthcoming regulatory period. More information on our 2023-28 revenue proposal can be found here.

We consider that the preferred option, as defined above, satisfies the RIT-T.

57 AEMC, *Transmission Planning and Investment Review*, Consultation Paper, 19 August 2021, p. 54.
58 Transgrid, *Revenue Proposal 2023–2028*, 31 January 2022, p. 112.

Appendix A Compliance checklist

This section sets out a compliance checklist which demonstrates the compliance of this PADR with the requirements of clause 5.16.4 of the National Electricity Rules version 182.

Rules clause	Summary of requirements	Relevant section(s) in the **PACR**
5.16.4(v)	The project assessment conclusions report must set out:	-
	(1) the matters detailed in the project assessment draft report as required under paragraph (k)	See below.
	(2) a summary of, and the RIT-T proponent's response to, submissions received, if any, from interested parties sought	3 Appendix E
5.16.4(k)	The project assessment draft report must include:	-
	(1) a description of each credible option assessed;	4
	(2) a summary of, and commentary on, the submissions to the project specification consultation report;	3
	(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	4 & 7
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	6 & Appendix D
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	6.6
	(6) the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);	7
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	7
	(8) the identification of the proposed preferred option;	8
	(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date; (iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and (iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission.	8

Appendix B Overview of existing electricity supply arrangements in the North West Slopes area

The North West Slopes area covers loads from Tamworth to Moree. The area is primarily supplied by 132 kV lines from the Tamworth 330/132 kV substation:

- Line 968 – Tamworth to Narrabri; and
- Line 969 – Tamworth to Gunnedah.

This part of the network is parallel to the 330 kV main system that interconnects the NSW and Queensland systems. Power flows on lines 968 and 969 are therefore affected by power flows on the NSW/Queensland interconnectors QNI and Directlink. At times of heavy power flows between the two states, the power flows on lines 968 and 969 can be significantly impacted by these main system flows.

The Narrabri and Gunnedah 132/66 kV substations supply Essential Energy loads in the area, with each substation having two 60 MVA 132/66 kV transformers. The Boggabri Coal and Maules Creek mines are also connected to the TransGrid 132 kV network via the Boggabri East and Boggabri North switching stations.

The current northern NSW electricity transmission network is shown in in Figure B-18 below with the area relevant for this RIT-T (the North West Slopes area) circled. The indicative location of the key forecast electricity loads that are discussed in this PACR (and are publicly announced) are also shown.

Figure B-18: Northern NSW transmission network

Electricity demand in the North West Slopes is forecast to increase significantly over the next ten years, primarily due to planned connections of new mining and industrial loads in the area.

Electricity demand from expected new mining loads

VCM was approved by the Independent Planning Commission of NSW in August 2020 and is expected to be connecting to the distribution network. The project is located in the Gunnedah Coalfield, which is approximately 25 km north of Gunnedah.[59]

The scope of the VCM project includes the construction of a new 66 kV/11 kV substation that would be serviced by an existing 66 kV overhead powerline.[60] In light of the project's location, it will likely be supplied by Transgrid's Gunnedah 132/66kV substation. This new additional load is expected to require supply from late 2024,[61] with maximum electricity demand when fully operational of approximately 62,700 MWh per annum.[62]

We were advised in a submission to the PADR that the Narrabri Coal expansion project was approved by the Independent Planning Commission in April 2022. This additional load for the existing Narrabri Coal Mine is expected to require increased supply from the final quarter of 2024, with maximum electricity demand of 32.8 MW in the first quarter of 2030. While this load was not included in the 2021 TAPR, it is will be in the forthcoming 2022 TAPR.

Essential Energy has also advised that Santos NSW (Eastern) Pty Ltd is proposing to develop the Narrabri Gas Project. The project canvasses connecting to the NSW power grid by drawing power from the existing Wilga Park Power Station via a new power distribution line.[63] As a result, it would be supplied from Transgrid's Narrabri 132/66 kV substation. This is not included in Essential Energy's base demand forecast. The specific load forecasts for this project have not been included in this PACR due to confidentiality reasons.

The Narrabri Gas Project has received development consent from the Federal Government,[64] contingent on a number of environmental conditions being met. Santos has announced that this approval will allow them to begin an appraisal program ahead of a Final Investment Decision (FID) for the next phase of project development.[65] The FID date is currently scheduled for first half 2023 and, once approved, stage 1 of production will require supply from 2026.[66]

The development of a pipeline that links the Narrabri project to the existing Moomba to Sydney Pipeline is being investigated by the APA group.[67] The proposed route would commence to the north of the Pilliga National Park and Pilliga West State Conservation Areas, before extending west-southwest to connect to the Moomba to Sydney Pipeline at the Bundure mainline valve station, approximately 100 km west of

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59 Australian Mining Monthly, *Vickery extension on track for 2021 construction completion,* 8 June 2019, available at: https://www.miningmonthly.com/development/international-coal-news/1364804/vickery-extension-on-track-for-2021-construction-completion; and Whitehaven Coal, *Vickery Extension Project Environmental Impact Statement | Introduction*, p 1-1, available at: https://majorprojects.planningportal.nsw.gov.au/prweb/PRRestService/mp/01/getContent?AttachRef=SSD-7480%2120190303T213410.742%20GMT.

60 Whitehaven Coal, *Vickery Extension Project Environmental Impact Statement | Project description*, p 2-18, available at: https://majorprojects.planningportal.nsw.gov.au/prweb/PRRestService/mp/01/getContent?AttachRef=SSD-7480%2120190303T213412.005%20GMT

61 This has been updated since the PADR, when 2023 was the expected commencement date.

62 Whitehaven Coal, *Vickery Extension Project Environmental Impact Statement | Project description*, p 2-31, available at: https://majorprojects.planningportal.nsw.gov.au/prweb/PRRestService/mp/01/getContent?AttachRef=SSD-7480%2120190303T213412.005%20GMT

63 Santos, *Narrabri Gas Project Environmental Impact Statement | Project description,* p 6-18, available at: https://majorprojects.accelo.com/public/1e6475194c440a225a59dddcb004fd53/Chapter%2006%20Project%20description.pdf

64 NSW planning portal website, https://www.planningportal.nsw.gov.au/major-projects/project/10716

65 Santos' Narrabri Gas Project website, https://narrabrigasproject.com.au/2020/11/santos-welcomes-federal-signoff-on-narrabri-gas-project/

66 Santos 2020 Investor Day 1 Dec 2020, available as "Santos upgrades 2020 guidance" at: https://www2.asx.com.au/markets/company/STO

67 APA group website project updates, https://www.apa.com.au/about-apa/our-projects/western-slopes-pipeline/project-updates/

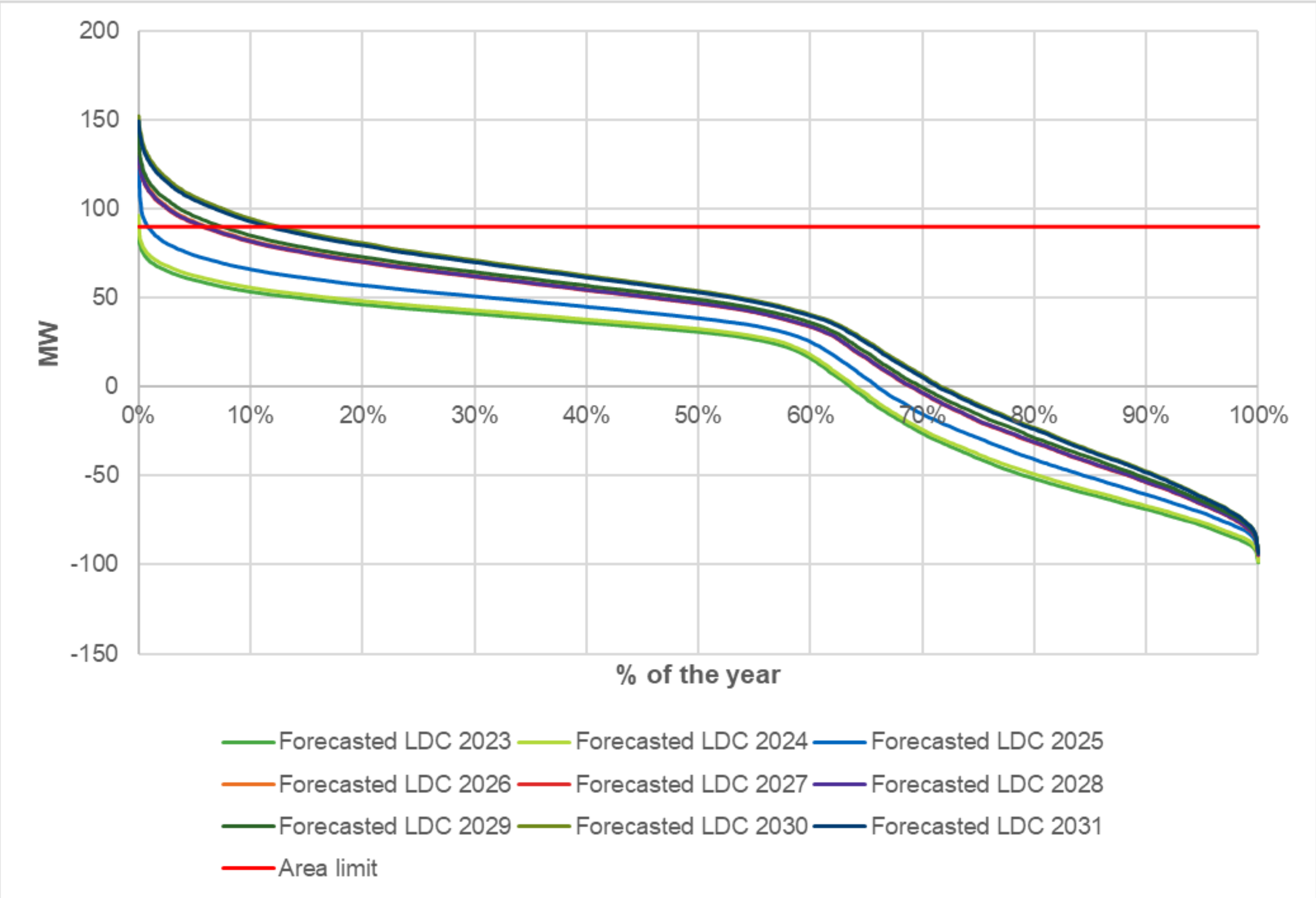
Condobolin. Should this gas pipeline not be installed, it may affect the ability to fully develop the Narrabri Gas Project (which in-turn has implications for the certainty of the electricity demand projections).

General system demand in the North West Slopes area

We forecast there to be steady load increases for the North West Slopes area over the next twenty years, with Narrabri having the greatest expected load increase.

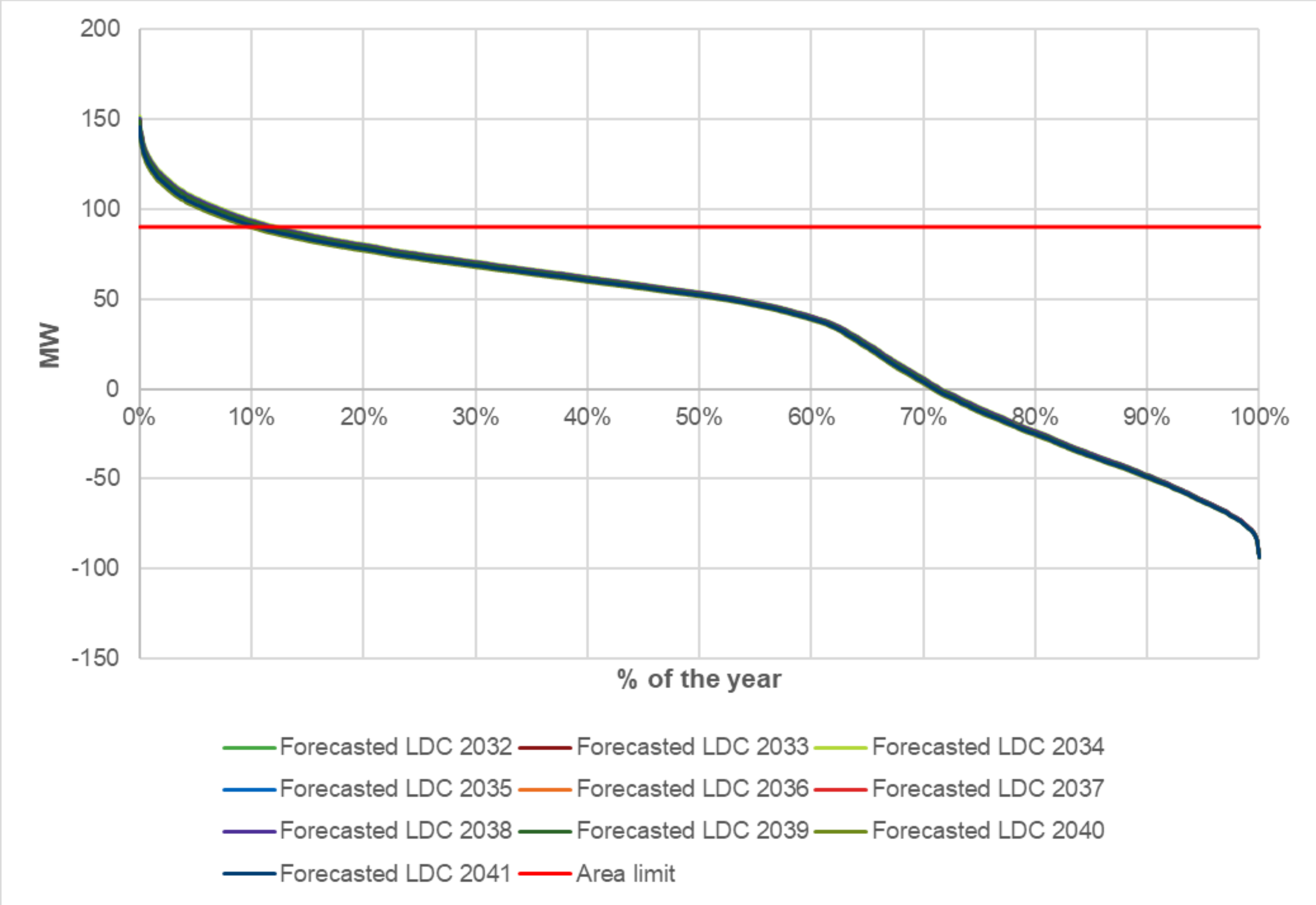
The two figures below present the actual 2019, as well as the forecast future, load duration curves (LDCs) and demand limits for the Narrabri and Gunnedah 66 kV BSP along with the existing and forecast mining loads under the central scenario. The LDCs represent the net demand (i.e., total demand minus committed embedded renewable generation in the area) and show the significant expected increase in demand going forward under the central forecast, as well as how the thermal and voltage limits are expected to be exceeded an increasing percentage of the year if action is not taken. This data provides a visual representation of the load that could be at risk during a calendar year under the central scenario if action is not taken.[68]

Figure 19: Forecasted LDCs and demand limits for the North West Slopes area to 2031 under the central demand forecasts



[68] The data shown in these LDCs is the aggregate of the load at Narrabri 66 kV, Boggabri North 132 kV, Boggabri East 132 kV and Gunnedah 66 kV, less the Gunnedah Solar Farm generation.

Figure 20: Forecasted LDCs and demand limits for the North West Slopes area, forecast 2032 to 2041 under the central demand forecasts



Renewable generation in the region

In addition to the longer-term voltage constraints, the forecast increased demand going forward is expected to also lead to thermal constraints, particularly at times of low renewable generation dispatch in the region.

There are a number of in-service and planned renewable generator connections in the northern NSW region. Table B-8-1 summarises these systems.

Table B-8-1: Current and planned renewable generation in the northern NSW region

Generating System	Connection location	Capacity (MW)	Status
Moree Solar Farm	Essential Energy's 66 kV Moree network	56	In-service
White Rock Wind and Solar Farm	White Rock substation	172.5	In-service
Gunnedah East Solar Farm	9U3 Gunnedah to Boggabri East 132 kV line (close to Gunnedah)	110	In-service
Tamworth Solar Farm	969 Tamworth to Gunnedah 132 kV line	65	Advanced*

**'Advanced' connection is in the connection application process with the connecting NSP.*

We note that there are also other new potential renewable energy generation projects proposed in the area that are not yet at a committed or advanced stage.

Additional renewable generation could assist with addressing/minimising the identified need as it can provide reactive support while generating active power subject to its voltage control strategy. We have taken account of in-service and committed renewable generation in assessing the identified need for this RIT-T.

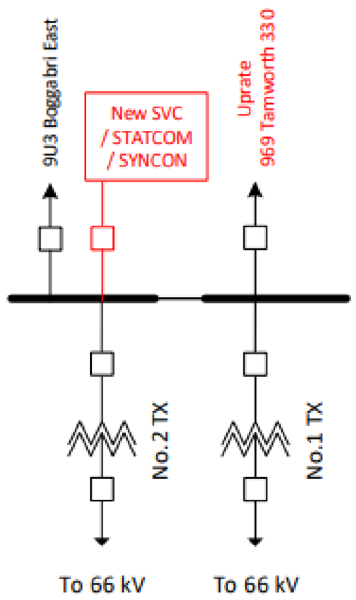
Appendix C Indicative line diagrams for each option

This appendix provides the line diagrams for each of the network elements of credible options considered in this PACR, as relevant. Existing elements are shown in black, while new elements are shown in red.

Option 1 – Uprating the existing line 969 from Tamworth to Gunnedah

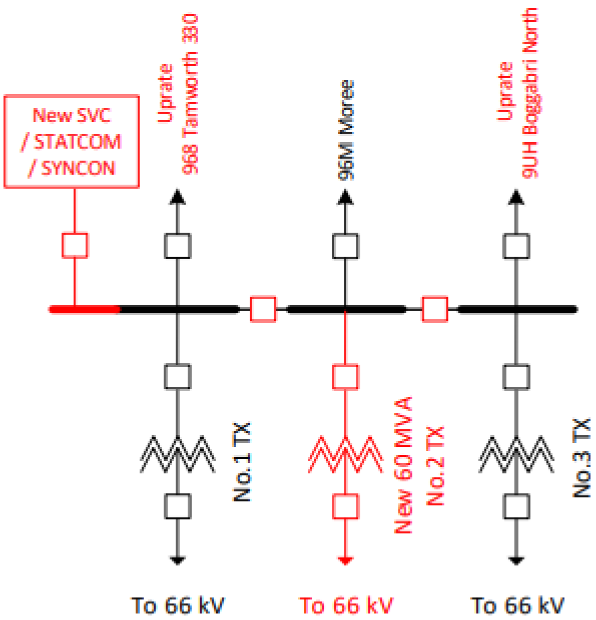
The indicative layout for the Gunnedah 132/66 kV substation under Options 1A and 1B is shown in Figure C-1 below.

Figure C-1: Indicative Gunnedah 132/66 kV substation layout under Options 1A and 1B



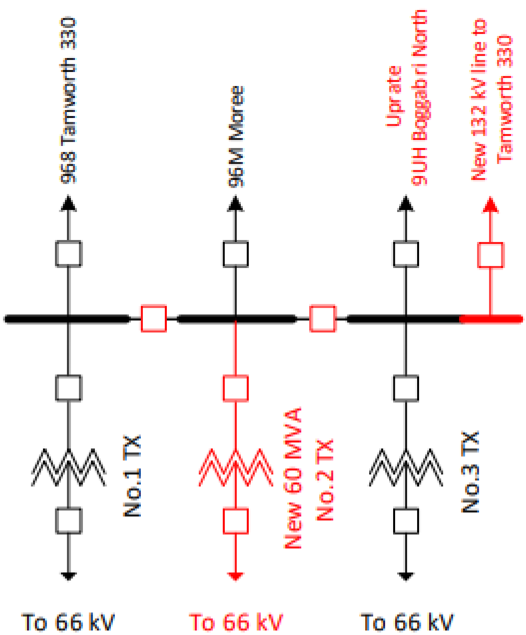
The indicative layout for the Narrabri 132/66 kV substation under Option 1A is shown in Figure C-2 below.

Figure C-2: Indicative Narrabri 132/66 kV substation layout under Option 1A



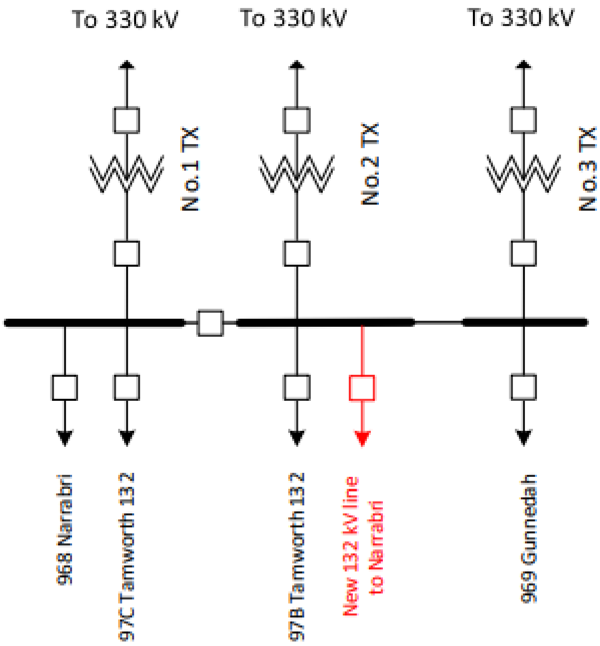
The indicative layout for the Narrabri 132/66 kV substation under Option 1B is shown in Figure C-3 below.

Figure C-3: Indicative Narrabri 132/66 kV substation layout under Option 1B



The indicative layout for the Tamworth 330/132 kV substation under Option 1B is shown in Figure C-4 below.

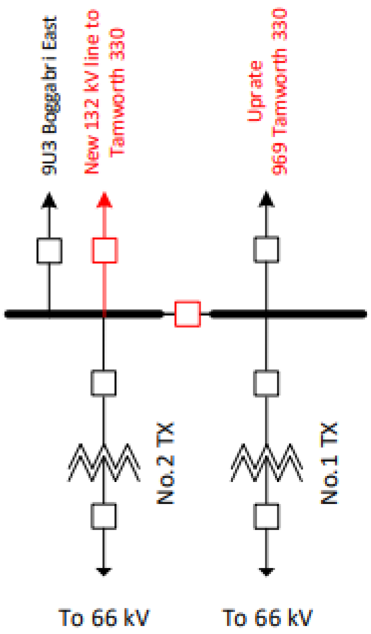
Figure C-4: Indicative Tamworth 330/132 kV substation layout under Option 1B



Option 2 – New single or double circuit transmission lines between Tamworth and Gunnedah

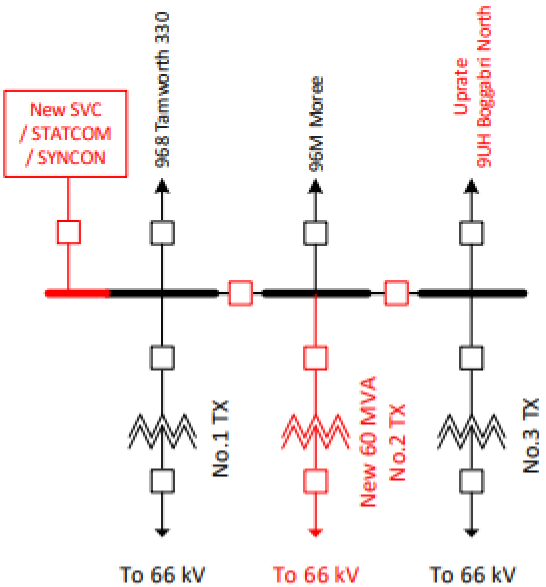
The indicative layout for the Gunnedah 132/66 kV substation under Option 2A is shown in Figure C-5 below.

Figure C-5: Indicative Gunnedah 132/66 kV substation layout under Option 2A



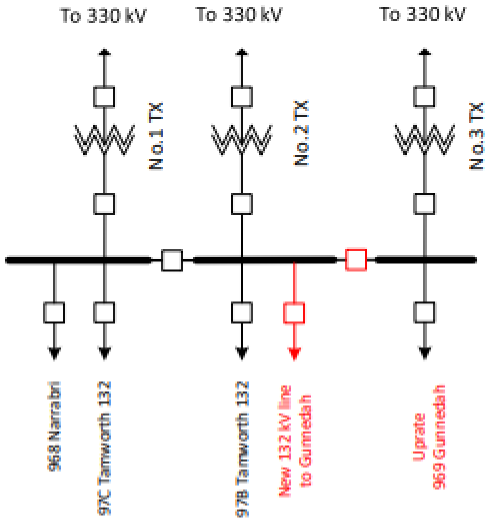
The indicative layout for the Narrabri 132/66 kV substation under Options 2A, 2B and 2D is shown in Figure C-6 below.

Figure C-6: Indicative Narrabri 132/66 kV substation layout under Options 2A, 2B and 2D



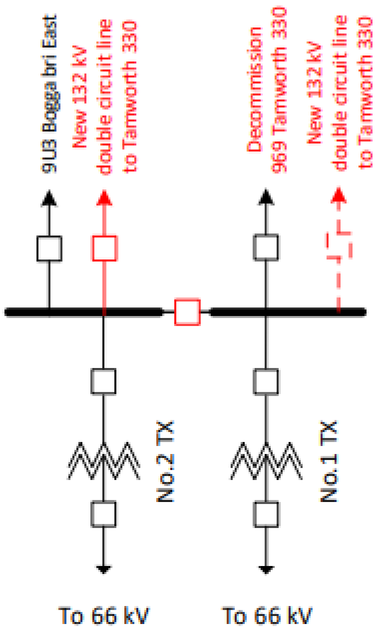
The indicative layout for the Tamworth 330/132 kV substation under Options 2A and 2C is shown in Figure C-7 below.

Figure C-7: Indicative Tamworth 330/132 kV substation layout under Options 2A and 2C



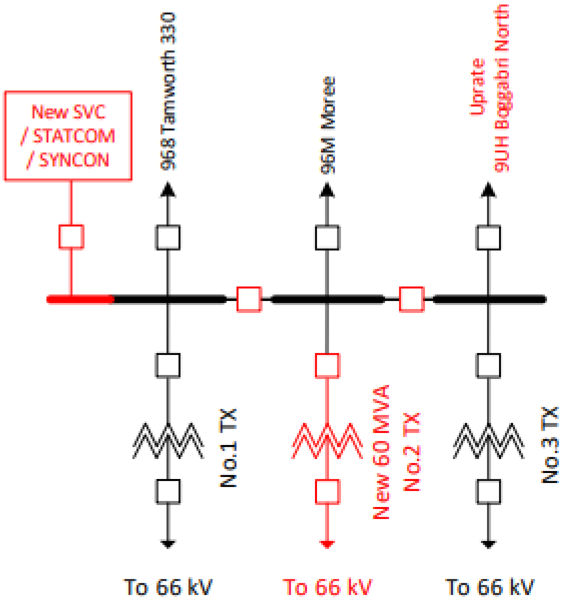
The indicative layout for the Gunnedah 132/66 kV substation under Option 2B is shown in Figure C-8 below.

Figure C-8: Indicative Gunnedah 132/66 kV substation layout under Option 2B



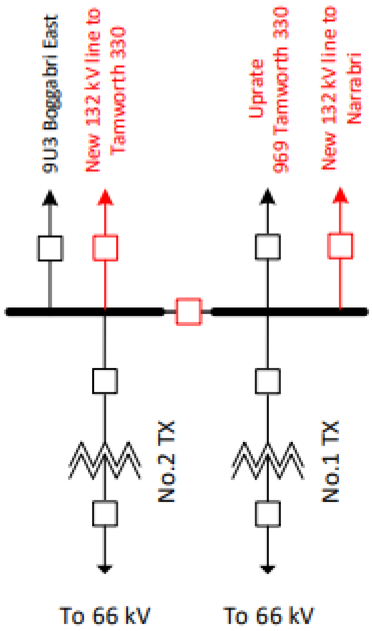
The indicative layout for the Tamworth 330/132 kV substation under Option 2B is shown in Figure C-9 below.

Figure C-9: Indicative Tamworth 330/132 kV substation layout under Option 2B



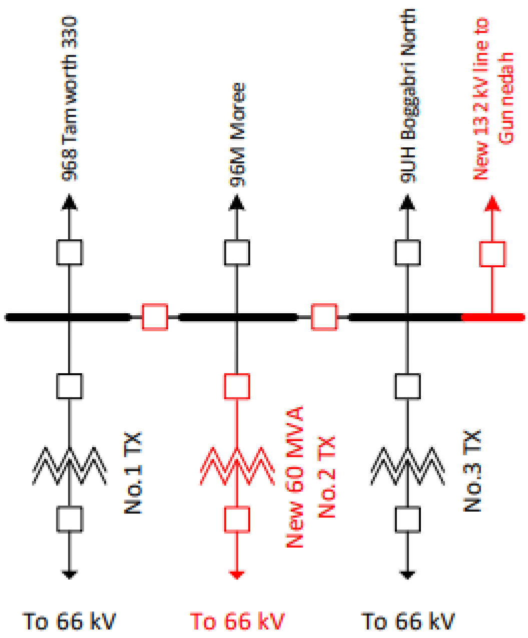
The indicative layout for the Gunnedah 132/66 kV substation under Option 2C is shown in Figure C-10 below.

Figure C-10: Indicative Gunnedah 132/66 kV substation layout under Option 2C



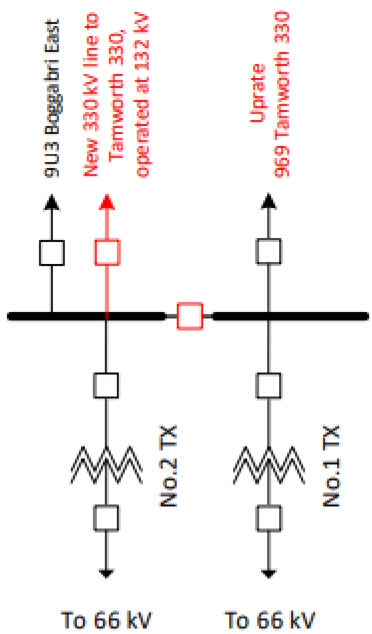
The indicative layout for the Narrabri 132/66 kV substation under Option 2C is shown in Figure C-11 below.

Figure C-11: Indicative Narrabri 132/66 kV substation layout under Option 2C



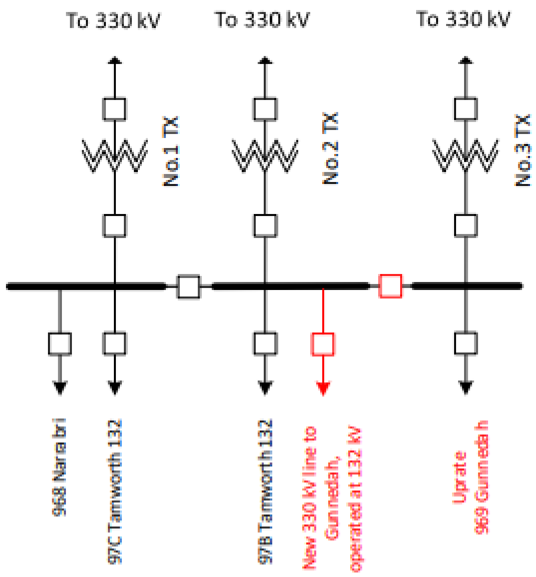
The indicative layout for the Gunnedah 132/66 kV substation under Option 2D is shown in Figure C-12 below.

Figure C-12: Indicative Gunnedah 132/66 kV substation layout under Option 2D



The indicative layout for the Tamworth 330/132 kV substation under Option 2D is shown in Figure C-13 below.

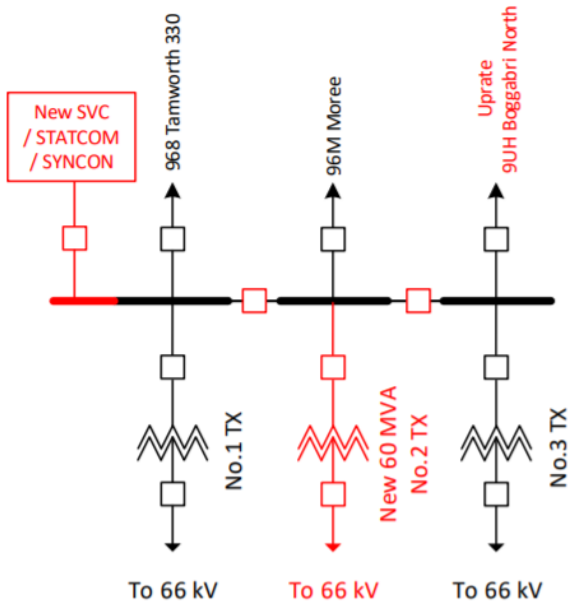
Figure C-13: Indicative Tamworth 330/132 kV substation layout under Option 2D



Option 3 – Rebuilding the existing line 969 from Tamworth to Gunnedah to be a double circuit line

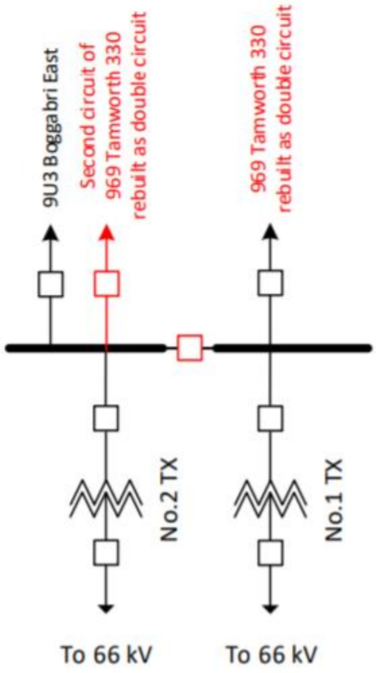
The indicative layout for the Narrabri 132/66 kV substation under Option 3A is shown in Figure C-14 below.

Figure C-14: Indicative Narrabri 132/66 kV substation layout under Option 3A



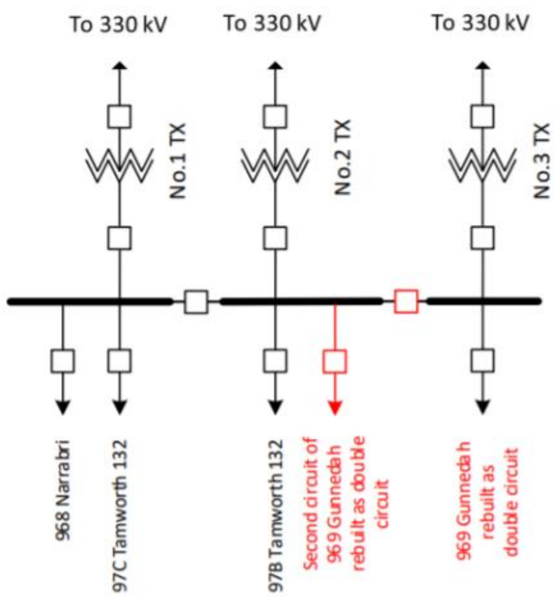
The indicative layout for the Gunnedah 132/66 kV substation under Options 3A and 3B is shown in Figure C-15 below.

Figure C-15: Indicative Gunnedah 132/66 kV substation layout under Options 3A and 3B



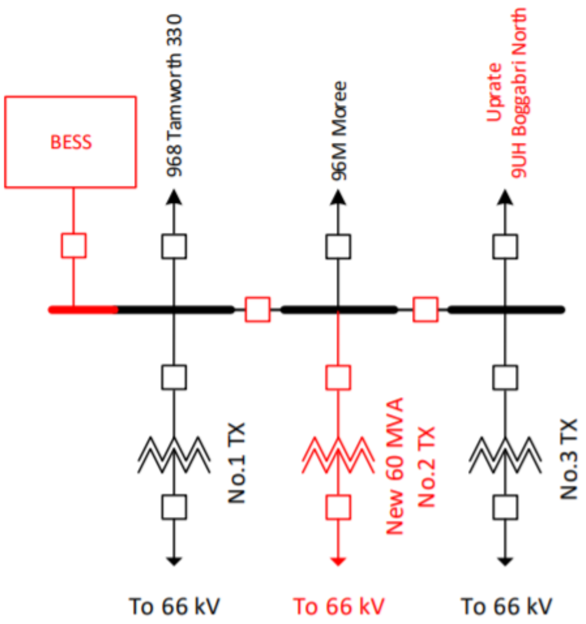
The indicative layout for the Tamworth 330/132 kV substation under Options 3A, 3B and 3C is shown in Figure C-16 below.

Figure C-16: Indicative Tamworth 330/132 kV substation layout under Options 3A, 3B and 3C



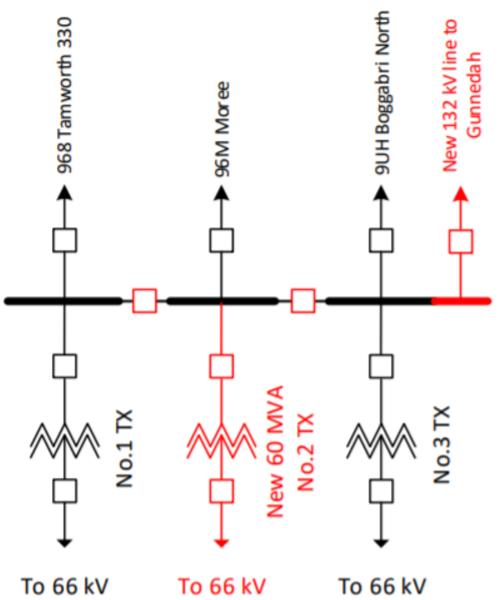
The indicative layout for the Narrabri 132/66 kV substation under Option 3B is shown in Figure C-17 below.

Figure C-17: Indicative Narrabri 132/66 kV substation layout under Option 3B



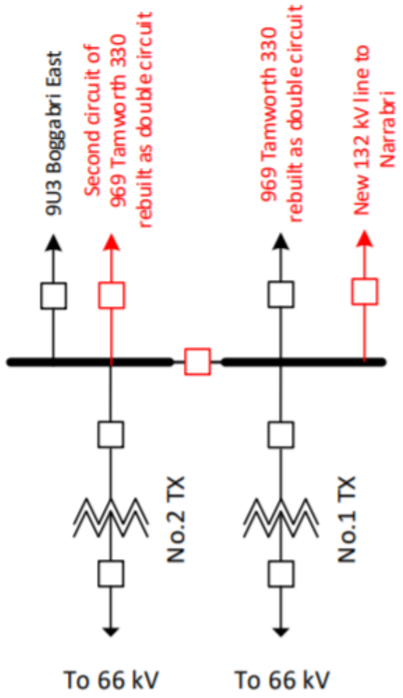
The indicative layout for the Narrabri 132/66 kV substation under Option 3C is shown in Figure C-18 below.

Figure C-18: Indicative Narrabri 132/66 kV substation layout under Option 3C



The indicative layout for the Gunnedah 132/66 kV substation under Option 3C is shown in Figure C-19 below.

Figure C-19: Indicative Gunnedah 132/66 kV substation layout under Option 3C



Appendix D Overview of the wholesale market modelling undertaken

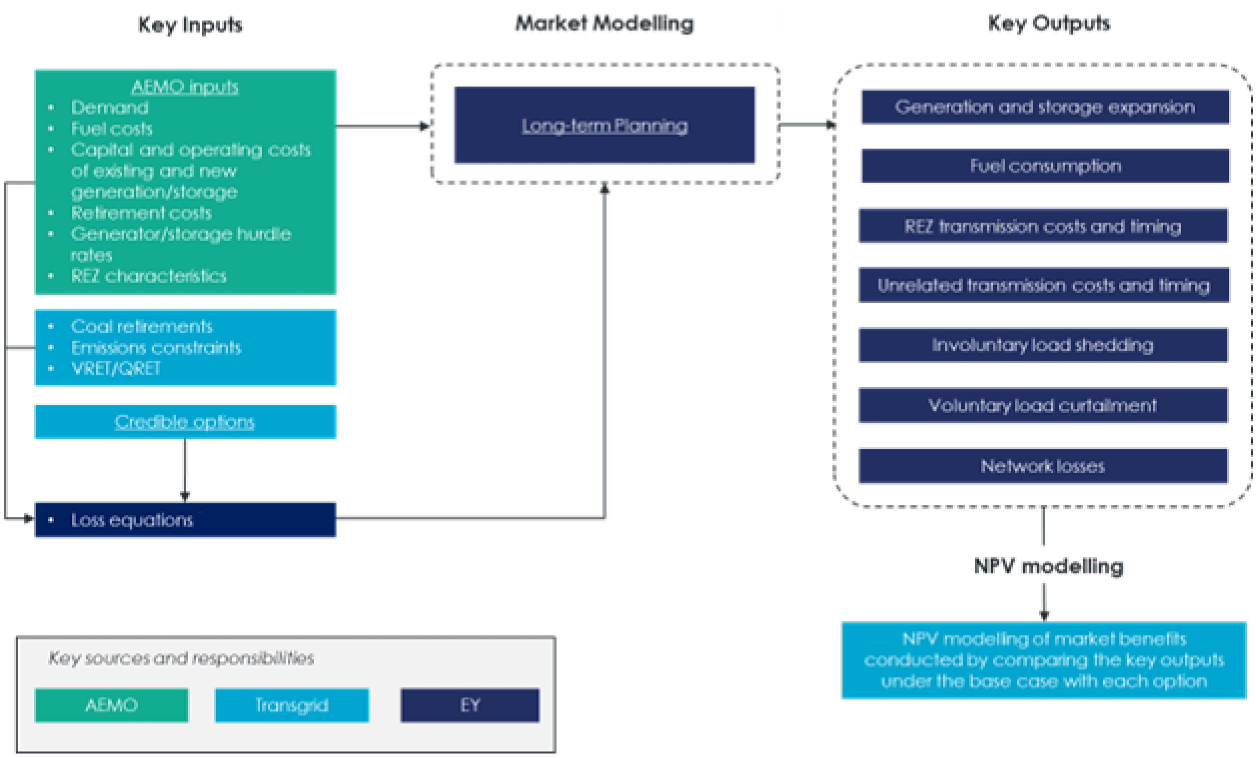
As outlined in the body of this PACR, we have engaged EY to undertake the wholesale market modelling as part of this PACR.

EY has applied a linear optimisation model and performed hourly, time-sequential, long-term modelling for the NEM to estimate categories of wholesale market benefits expected under the options that affect the wholesale market. Specifically, EY has undertaken market simulation exercise involving long-term investment planning, which identifies the optimum generation (including storage) and unrelated transmission infrastructure development schedule, while meeting reserve requirements, policy objectives, and technical generator and network performance limitations. This solves for the least-cost generation and transmission infrastructure development across the assessment period while meeting energy policies.

These exercises are consistent with an industry-accepted methodology, including within AEMO's ISP.

Figure D-1 illustrates the interactions between the key modelling exercises, as well as the primary party responsible for each exercise and/or where the key assumptions have been sourced.

Figure D-1: Overview of the market modelling process and methodologies



** As outlined in section 6.2, the avoided involuntary load shedding in the North West Slopes region of NSW has been estimated separately by Transgrid.*

The sub-sections below provide additional detail on the key wholesale market modelling exercises EY have undertaken as part of this PACR assessment.

Long-term Investment Planning

The Long-term Investment Planning's function is to develop generation (including storage) and unrelated transmission infrastructure forecasts over the assessment period for each of the credible options and base cases.

This exercise determines the least-cost development schedule for each credible option drawing on assumptions regarding demand, emissions reduction and renewable energy targets, reservoir inflows, generator outages, wind and solar generation profiles, and maintenance over the assessment period.

The generation and transmission infrastructure development schedule resulting from the Long-term Investment Planning is determined such that:

- it economically meets hourly regional and system-wide demand while accounting for network losses;
- it builds sufficient generation capacity to meet demand when economic while considering potential generator unplanned and planned outages;
- the cost of unserved energy is balanced with the cost of new generation investment to supply any potential shortfall;
- generator's technical specifications such as minimum stable loading, and maximum capacity are observed;
- notional interconnector flows do not breach technical limits and interconnector losses are accounted for;
- hydro storage levels and battery storage state of charge do not breach maximum and minimum values and cyclic losses are accounted for;
- new generation capacity is connected to locations in the network where it is most economical from a whole of system cost;
- NEM-wide emissions constraints are adhered to;
- NEM-wide and state-wide renewable energy targets are met;
- regional and mainland reserve requirements are met;
- energy-limited generators such as Tasmanian hydro-electric generators, Snowy Hydro-scheme and grid-scale batteries are scheduled to minimise system costs; and
- the overall system cost spanning the whole outlook period is optimised whilst adhering to constraints.

The Long-term Investment Planning adopts the same commercial discount rate as used in the NPV discounting calculation in the cost benefit analysis. This is consistent with the approach being taken in the 2022 ISP (and was applied in the 2020 ISP and the inaugural 2018 ISP).[69]

Coal-fired and gas-fired generation is treated as dispatchable between its minimum load and its maximum load in the modelling. Coal-fired 'must run' generation is dispatched whenever available at least at its minimum load. Open cycle gas turbines are typically bid at their short run marginal cost with a zero minimum load level, and started and operated whenever the price is above that level.

[69] AEMO, *Planning and Forecasting 2019 Consultation Process Briefing Webinar*, Wednesday 3 April 2019, slide 21.

The Long-term Investment Planning model ensures there is sufficient dispatchable capacity in each region to meet peak demand in the region, plus a reserve level sufficient to allow for generation or transmission contingences which can occur at any time, regardless of the present dispatch conditions.

Due to load diversity and sharing of reserve across the NEM, the reserve to be carried is minimised at times of peak, and provided from the lowest cost providers of reserve including allowing for each region to contribute to its neighbours reserve requirements through interconnectors.

Modelling of diversity in peak demand

The market modelling accounts for peak period diversification across regions by basing the overall shape of hourly demand on nine historical years ranging from 2010/11 to 2018/19.

Specifically, the key steps to accounting for this diversification are as follows:

- the historical underlying demand has been calculated as the sum of historical metered demand and the estimated rooftop PV generation based on historical rooftop PV capacity and solar insolation;
- the nine-year hourly pattern has been projected forward to meet future forecast annual peak demand and energy in each region;
- the nine reference years are repeated sequentially throughout the modelling horizon; and
- the future hourly rooftop PV generation has been estimated based on insolation in the corresponding reference year and the projection of future rooftop PV capacity, which is subtracted from the forecast underlying demand along with other behind-the-meter components (e.g., electric vehicles and domestic storage) to get a projection of hourly operational demand.

This method ensures the timing of peak demand across regions reflects historical patterns, while accounting for projected changes in rooftop PV generation and other behind-the-meter loads and generators that may alter the diversity of timing.

Modelling of intra-regional constraints

The wholesale market simulations include models for intra-regional constraints in addition to the inter-regional transfer limits.

Key intra-regional transmission constraints in New South Wales have been captured by splitting NSW into zones (NNS, NCEN, CAN and SWNSW), and explicitly modelling intra-regional connectors across boundaries or cut-sets between these zones. Bi-directional flow limits and dynamic loss equations were formulated for each intra-regional connector.

Summary of the key assumptions feeding into the wholesale market exercise

The table below summarises the key assumptions that the market modelling exercise draws upon.

Table D-1: PACR modelled scenario key drivers input parameters

Key drivers input parameters	Step change	Progressive change	Hydrogen superpower
Underlying consumption	ESOO 2021 (draft ISP 2022) – step change	ESOO 2021 (draft ISP 2022) – progressive change	ESOO 2021 (draft ISP 2022) – hydrogen superpower
New entrant capital cost for wind, solar PV, SAT, OCGT, CCGT, PSH, and large-scale batteries	2021 Inputs and Assumptions Workbook – step change	2021 Inputs and Assumptions Workbook – progressive change	2021 Inputs and Assumptions Workbook – hydrogen superpower
Retirements of coal-fired power stations	2021 Inputs and Assumptions Workbook – step change In line with expected closure year, or earlier if economic or driven by decarbonisation objectives	2021 Inputs and Assumptions Workbook – progressive change In line with expected closure year, or earlier if economic or driven by decarbonisation objectives beyond 2030	2021 Inputs and Assumptions Workbook – hydrogen superpower In line with expected closure year, or earlier if economic or driven by decarbonisation objectives
Gas fuel cost	2021 Inputs and Assumptions Workbook – step change Lewis Grey Advisory 2020, step change	2021 Inputs and Assumptions Workbook – progressive change Lewis Grey Advisory 2020, central	2021 Inputs and Assumptions Workbook – hydrogen superpower Lewis Grey Advisory 2020, step change
Coal fuel cost	2021 Inputs and Assumptions Workbook – step change Wood Mackenzie, step change	2021 Inputs and Assumptions Workbook – progressive change Wood Mackenzie, central	2021 Inputs and Assumptions Workbook – hydrogen superpower Wood Mackenzie, step change
NEM carbon budget to achieve 2050 emissions levels	2021 Inputs and Assumptions Workbook – step change 891 Mt CO_2-e 2023-24 to 2050-51	2021 Inputs and Assumptions Workbook – progressive change 932 Mt CO_2-e 2030-31 to 2050-51	2021 Inputs and Assumptions Workbook – hydrogen superpower 453 Mt CO_2-e 2023-24 to 2050-51
Victoria Renewable Energy Target (VRET)	40 % renewable energy by 2025 and 50 % renewable energy by 2030 VRET 2 including 600 MW of renewable capacity by 2025		
Queensland Renewable Energy Target (QRET)	50 % by 2030		
Tasmanian Renewable Energy Target (TRET)	2021 Inputs and Assumptions Workbook: 200 % Renewable generation by 2040		
NSW Electricity Infrastructure Roadmap	2021 Inputs and Assumptions Workbook: 12 GW NSW Roadmap, with 3 GW in the Central West Orana (CWO) REZ, modelled as generation constraint per the draft 2022 ISP 2 GW of long duration storage (8 hrs or more) by 2029-30		
EnergyConnect	Draft 2022 ISP – EnergyConnect commissioned by July 2025		
Western Victoria Transmission Network Project	Draft 2022 ISP – Western Victoria upgrade commissioned by November 2025		
HumeLink	Draft 2022 ISP – step change: HumeLink commissioned by July 2028	Draft 2022 ISP – progressive change: HumeLink commissioned by July 2035	Draft 2022 ISP – hydrogen superpower: HumeLink commissioned by July 2027
MarinusLink	Draft 2022 ISP – 1st cable commissioned by July 2029 and 2nd cable by July 2031		
Victoria to NSW Interconnector Upgrade (VNI Minor)	Draft 2022 ISP – VNI Minor commissioned by December 2022		
NSW to QLD Interconnector Upgrade (QNI Minor)	Draft 2022 ISP – QNI minor commissioned by July 2022		

Key drivers input parameters	Step change	Progressive change	Hydrogen superpower
QNI Connect	Draft 2022 ISP – step change: QNI Connect commissioned by July 2032	Draft 2022 ISP – progressive change: QNI Connect commissioned by July 2036	Draft 2022 ISP – hydrogen superpower: QNI Connect commissioned by July 2029 and stage 2 to be commissioned by July 2030
VNI West	Draft 2022 ISP – step change: VNI West commissioned by July 2031	Draft 2022 ISP – progressive change: VNI West commissioned by July 2038	Draft 2022 ISP – hydrogen superpower: VNI West commissioned by July 2030
Victorian SIPS	Draft 2022 ISP – 300 MW/450 MWh, 250 MW for SIPS service and the remaining 50 MW can be deployed in the market by the operator on a commercial basis, November 2021.		
New-England REZ Transmission	Draft 2022 ISP – step change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2035	Draft 2022 ISP – progressive change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2038	Draft 2022 ISP – hydrogen superpower: New England REZ Transmission Link commissioned by July 2027, and New England REZ Extension commissioned by July 2031
Snowy 2.0	2021 Inputs and Assumptions Workbook – Snowy 2.0 is commissioned by December 2026		

Appendix E Summary of consultation on the PADR

This appendix provides a summary of points raised by stakeholders during the PADR consultation process, besides those raised in confidential submissions.

The points raised are grouped by topic and a response is provided to every point raised. All section references are to this PACR, unless otherwise stated.

Summary of comment(s)	Submitter(s)	Our response
Demand forecasts		
Ensuring that mining/industrial loads are accounted for in demand forecasts		
Confirmation of intent to proceed with the Narrabri Coal Stage 3 expansion project, which received approval from the Independent Planning Commission on 1 April 2022[70] and is on schedule to require additional load from Q4 2024/Q1 2025 with a peak in Q4 2029/Q1 2030 (further details provided).	Whitehaven Coal, p. 1 (Narrabri Coal submission)	Section 2.3.1 outlines how the Narrabri Coal Stage 3 expansion project has now been reflected in the central demand forecast for this PACR.
Confirmation of intent to proceed with the Vickery expansion project, which has received state and federal approval and will require power by Q4 2024, with a maximum demand of 12.5 MVA.	Whitehaven Coal, p. 1 (Vickery expansion project submission)	
Ensuring that regional growth and proposed developments are appropriately accounted for in demand forecasts		
PIAC is concerned that demand forecasts based on regional growth plans may not be met, and recommends any projected demand relating to regional growth plans should be based on an independent assessment that takes into account the actual approved and/or financially committed developments.	PIAC, p. 1	See section 3.1. The Narrabri SAP has not been included in the assessment given the information provided by stakeholders regarding its commitment status.
PIAC is concerned about demand forecasts being treated as commercial-in-confidence, and considers that these forecasts should be released if costs are expected to be recovered from consumers.	PIAC, p. 1	See section 3.1.
Estimating the market benefits of the options		

[70] https://www.ipcn.nsw.gov.au/projects/2021/12/narrabri-underground-mine-stage-3-extension-project-ssd-10269

Summary of comment(s)	Submitter(s)	Our response
Development of reasonable scenarios		
PIAC expressed a view that the high benefits scenario should not be included in the analysis due to unrealistic assumptions (25 per cent lower network capital costs, a high VCR estimate, and a low discount rate of 2.23 per cent).	PIAC, p. 1	See section 3.1.
PIAC recommends a more realistic approach of applying 50 per cent weighting to each of the central and low net economic benefits scenarios.	PIAC, p. 2	See section 3.2.